INTEGRATED ENERGY POLICY REPORT COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)	
	)	
The Preparation of the 2005	)	
Integrated Energy Policy Report	)	Docket No.
	)	04-EP-01E
California's New Electricity	)	
Resource Loading Order	)	
	)	

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

MONDAY, JULY 25, 2005

9:41 a.m.

Reported by:
Peter Petty
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COMMISSIONERS PRESENT

John L. Geesman, Presiding Member

James D. Boyd, Associate Member

Jackalyn Pfannenstiel

ADVISORS

Melissa Jones, Advisor

Michael Smith, Advisor

Tim Tutt, Advisor

STAFF PRESENT

John Sugar

Sylvia Bonder

Mike Messenger

Mark Rawson

David Hungerford

Pamela Doughman

Marwan Masri

Heather Raitt

ALSO PRESENT

Barbara George, Executive Director
Women's Energy Matters

Gary Schoonyan, Director
Southern California Edison

Manuel A. Robledo, Energy Systems Manager
SCPPA

APPEARANCES (continued)

ALSO PRESENT

Karen Lindh
Lindh & Associates

Robert Freehling, Research Director
Local Power

Les Guliasi, Director, State Agency Relations
Pacific Gas and Electric

Steven Kelly, Policy Director
Independent Energy Producers

Alex Leupp
NCPA

Nick Zettel, Resources Group
Redding Electric Utility

Rod S. Aoki
Alcantar & Kahl LLP

Loren Kaye
Kahl/Pownall Advocates

Eric R. Wong, Manager
Power Generation

I N D E X

P R O C E E D I N G S

9:41 a.m.

MS. BENDER: There are two important points that need to be made about how progress towards the goals will be measured and evaluated in this next period.

First, in a move toward more independent evaluation, those who evaluate will be separated from those who run programs. The CPUC and the CEC will assume that role in the future. Even consulting firms must choose whether the firm will be a program implementor or a program evaluator.

Second, a new set of evaluation protocols will reinforce energy efficiency as a more certain resource option by confirming savings through rigorous evaluation.

The new protocols will put certainty into efficiency savings in several ways. First by a renewed emphasis on impact evaluation --

PRESIDING MEMBER GEESMAN: What does that mean?

MS. BENDER: Actually measuring with details, statistical analysis, on-site verification, the savings that have actually been installed and achieved.

PRESIDING MEMBER GEESMAN: Okay.

MS. BENDER: -- by providing quality assurance through definitions and guidance on acceptable methods for carrying out the studies and reporting results, by establishing defensible metrics to assess effectiveness of what are called non-resource programs, such as the codes and standards advocacy and emerging technologies, and for some of these to consider ways in which savings might actually be attributed to them.

Finally, by developing and evaluation cycle that incorporates process evaluations, impact evaluations, and market assessment for all programs over the three year program cycle.

PRESIDING MEMBER GEESMAN: How do other states conduct this measurement and evaluation?

MS. BENDER: Very similarly. It is done through our national meetings. In fact, there is one in about three weeks where evaluators from all over the country who deal with energy efficiency meet to talk about these practices and methods. It is a relatively small community of people that actually do this.

PRESIDING MEMBER GEESMAN: There is a consistent set of protocols used across the country?

MS. BENDER: With a great deal of similarity. California has an evaluation framework which provides guidance on how to do these. They were prepared by a team of national consultants. The volume is used by many other states as a model.

PRESIDING MEMBER GEESMAN: Is it a regulatory requirement or a accounting requirement at this point, or is it a more informal type of guidance?

MS. BENDER: Right now it is a more informal type of guidance, the protocols, however, will codify it into something that will be more of a regulatory reporting requirement that all evaluators who are working with California programs will follow.

PRESIDING MEMBER GEESMAN: Have other states taken it to that level of formality?

MS. BENDER: Wisconsin certainly does. Other states evaluate in different ways. I would say the Northwest probably evaluates with about that much rigor.

PRESIDING MEMBER GEESMAN: Currently there is not a national set of standards akin to the Financial Accounting Standards Board or the Government Accounting Standards Board?

MS. BENDER: There is, in fact, an international set of measurement verification protocols which have to do more with on-site actual verifications. They don't go into the econometric and statistical analyses that the load impact probably does, which might use things like billing date or load shapes in addition to engineering estimates.

PRESIDING MEMBER GEESMAN: Who would adopt these protocols, the PUC or the individual utilities --

MS. BENDER: The PUC.

PRESIDING MEMBER GEESMAN: Thank you.

MS. BENDER: While achieving the near term goals looks possible, more questions surround the longer term goals going out to 2013. Much could affect the achievement of these goals and the success of the new evaluation framework.

The following two slides present a summary of the key uncertainties, constraints, and issues for efficiency.

The data used to develop the 2006 - 2008 portfolios was based on potential data collected in 2000. Equipment saturation levels are very likely to be different for one thing. A new study projected for late August 2005 could show higher or lower potential going forward.

The policy objectives for the 2006-08 programs remain somewhat ambiguous in at least four ways. Parties disagree on whether the emphasis on achieving cost effective sayings results in more KWh savings than KW savings, and emphasizing one over the other or trying to find a balance between the two is an issue still to be addressed.

Another area of concern is whether the move to counting installed savings only drives program focus to lighting measures rather than air conditioning programs which can be slower to achieve savings.

Three definitions of peak savings are causing confusion about whether proposed KW savings are comparable across the IOU's and even whether the requisite amount can be achieved.

PRESIDING MEMBER GEESMAN: When you say three, you mean each company has a different approach?

MS. BENDER: No, there are three

possibilities in the calculator that is being used to calculate cost effectiveness, the avoided costs, so it is not always certain who is using which one. There is a coincident, non-coincident, and then there is a third one which matches the way the CEC recommended the goals be calculated which is a factor that multiplies GWhs to get to a MWh to a peak demand savings. There are three different possibilities. One needs to be agreed upon at some point for reporting purposes.

Several aspects of the performance basis are yet to be decided. For example, whether or not performance incentives for administrators will be used and whether there will be a plus or minus range around the goals.

Given the number of new program strategies, new implementors, and the large increases in spending for this round, ramping up the programs may be slower than anticipated.

A number of key performance metrics, such as the hours of operation, useful measure life, net to growth ratios are also in need of updating. Inaccuracies in these values can make it harder to achieve future savings and reduce previously projected savings.

Questions about building standards, compliance levels, and enforcement consistency related to the standards raises additional uncertainty about program savings.

If the long term goals are to be met, utilities will need to increase their reach to their customers. Consumers will need to be better understood in terms of their levels of concern, their capacity to act, and the conditions surrounding their decisions.

The evaluation and measurement agenda currently has approximately four to five staff not working at their full responsibility in this area between the CPUC and the Energy Commission to oversee the evaluation of approximately $600 million over 36 programs for 2006.

I am going to close with two slides that list some of the options for reducing these uncertainties and constraints.

Wind efficiency programs more directly to this state's energy policies by broadening the ways in which they are used. For example, transmission constraints and rising natural gas prices are other policy concerns that efficiency programs could address.

The standards could be thought of as being part of a continuous cycle that begins with PIERS research and development work, moves through a commercialization, a market acceptance process with the Public Utilities Public Benefit Programs and culminates with the establishment of a new codified threshold from which the process begins again.

Policy makers and the public need to know that their money has been well spent. Information and feedback about program results needs to move beyond the energy efficiency community to these audiences.

Program feedback also needs to address the different needs of resource planners from program designers and implementors, some of these issues that we've talked about touch on these points.

The parameters we use to evaluate the net savings and the cost effectiveness of the programs need to be clearly defined, accurate, and updated on a regular basis to insure reliable savings and improve future programs.

Efforts to conduct residential new construction programs and market efficiency and conservation marketing campaigns on a coordinated statewide basis should be supported. An evaluation on the effectiveness of previous marketing campaigns should also be undertaken.

Regulatory staff need more than tracking data, annual summaries, and evaluation reports to be successful at evaluating net program benefits and their impacts on end use and sector load shapes. That is where the programs really matter.

We both additional staffing and data to do this. Without access to billing, interval meter and load data, regulatory staff will be unable to analyze how California's end use demand is changing in response to the millions of dollars we are spending on energy efficiency.

COMMISSIONER PFANNENSTIEL: Sylvia, before you leave that slide, I'm still at your first bullet frankly. The link programs to state's energy policy objectives. Where does that happen? Your discussion of it went from PIER work, in other words what is possible, but if you work it the other way and say what do we really want, where do we really want to focus these areas, is that something the PUC does every three years in setting up the program guidelines for the utilities? Where does that come from?

MS. BENDER: I think that is probably where it has been happening, but we also now have the Energy Action Plan and we have this process, and those processes need to be integrated in a way that they are following -- the programs are following on both state policies.

COMMISSIONER PFANNENSTIEL: The utilities who are implementing have the ability to revise their programs as they see necessary to follow state policy?

MS. BENDER: Within a three year cycle and then with some possibilities for shifting in between. I don't imagine state policy will shift too dramatically in three years, but following a three-year cycle with a series of policies that are laid out. Resource planning is looking ahead 20 years, so we are only looking ahead 10 years at this point in three year increments.

COMMISSIONER PFANNENSTIEL: That then does get back to the Public Utilities Commission in setting the three year program interprets energy policy to do that. Then how much flexibility do the utilities have to change dollars among programs during the three year cycle?

MS. BENDER: That is another aspect of the programs going forward that is still being worked on. There are several three proposals actually that are still being considered, but they are asking for enough flexibility to be able to match programs to shifting needs if something like the crisis were to happen again or something would change in terms of a program being wildly popular and able to achieve much more success than planned. They are asking for enough flexibility to be able to follow some of those kinds of needs.

COMMISSIONER PFANNENSTIEL: Thank you.

MS. BENDER: There's also some discussion about how to deal with totally new ideas that might come along, and so that is another point that is still up for discussion at the public utilities and the process going forward.

MS. JONES: Sylvia, could you just comment on what the time frame is at the PUC for this kind of evaluation?

MS. BENDER: For the evaluation to the protocols and the framework itself to be finished?

MS. JONES: Yeah.

MS. BENDER: By the end of the year, so they are in place for 2006.

MS. JONES: The flexibility then and the other issues that you just talked about would be addressed by the end of this year?

MS. BENDER: Those should be in place for the beginning of the new program cycle.

MS. JONES: Great, thank you.

MS. BENDER: Mike is saying September, I am saying by the end of the year.

PRESIDING MEMBER GEESMAN: So that issues like whether we should be focused on peak savings or energy savings or how to define peak savings are all issues then that you anticipate being resolved by the CPUC by the end of this year?

MS. BENDER: At least for the next three year program cycle.

PRESIDING MEMBER GEESMAN: Okay.

MS. BENDER: On the last slide here, we need to update our information on the benefits we've already derived from the building and appliance standards and what we can expect from them in the future. We haven't done this since 1995.

New forms of customer feedback are needed. What is the best combination of feedback, how much, when, these are still questions we cannot necessarily answer. The AB549 work offers a variety of new strategies that could involve new market participants and new avenues for customer interaction with programs.

More importantly, we need to know more about the customer's perspective on energy efficiency and maybe the energy system in general if we are going to get the right kind of incentives in front of customers.

Finally, we might be more successful and more cost effective at meeting our peak demand needs if we think about using demand response and distributed generation with energy efficiency as a different but complimentary strategies within markets rather than treating them as stand-alone programs.

PRESIDING MEMBER GEESMAN: Let me ask you to elaborate a bit more on the AB549 work. My understanding is that is supposed to cover the entire retrofit sector which to me anyway would appear to be a rather large proportion of the opportunities for potential future savings.

MS. BENDER: It would be, yes.

PRESIDING MEMBER GEESMAN: Are we supposed to adopt an AB549 set of recommendations this year?

MS. BENDER: I believe so. I believe the report is due --

COMMISSIONER PFANNENSTIEL: Yes, October 1 the Energy Commission needs to make a report to the Legislature with proposals.

PRESIDING MEMBER GEESMAN: Okay. So, it would be premature I guess to ask what those recommendations look like or what savings are attributal to those strategies compared to other programs?

MS. BENDER: Actually, they've just issued their draft report which does make recommendations and does give you some look at what the potential for savings and the costs would be.

PRESIDING MEMBER GEESMAN: I'll take a look at that.

Your last bullet, I wonder if you could elaborate on some of the issues of that integration and try to reassure me that it is not a case of mission creep just expanding programs to real blurry parameters.

MS. BENDER: What I am thinking about here is looking at them as alternatives rather than one on top of another necessarily or one here, one here, and one there. We have all of them separated into individual proceedings. We talk about the loading order as always being stacked assuming that one has to come before another, and it just strikes that there are probably some different ways to look at this. I am not sure I have the answers to this, but there are some alternative ways of looking at these programs and how they might fit in particular needs in different ways.

PRESIDING MEMBER GEESMAN: Can you share with us what some of those alternatives might be?

MS. BENDER: If we are looking -- oh, Mike is going to jump up here and speak again. Do you want to? Go ahead.

PRESIDING MEMBER GEESMAN: Turn your microphone on, Mike.

MR. MESSENGER: I will. Thank you, Commissioner. This particular one I want to speak to because I've been involved in both demand response and energy efficiency. This was actually started a couple of years ago when we ran into problems with customers saying, you know, you pitched a DR program to me, but you forgot to tell me about the energy efficiency opportunities in my building.

So, now that I am stuck in this DR program, I don't feel like I can get the energy efficiency or vice versa. So, what this bullet generally means when utilities are talking about is when they go to a customer now, they say, look, we don't just offer energy efficiency programs, we offer a menu of programs; DG, DR, EE.

You can have any of these that you want, and we will work with you to make sure that there are not overlaps that perhaps eliminate you from one program or take you to the point where you feel like you are stuck with a piece of DR machinery, for example, when you really wanted something to do with an energy efficiency investment.

The first part is this is at the customer entry point trying to make sure they understand all of the option.

The second point is that one of the things that we have talked about in the energy efficiency proceedings is trying to make sure that you don't make energy efficiency programs do too much with respect to meeting critical peak demands. It is a bit of a stretch, for example, to make a more efficient air conditioner program function so that it only reduces peak during that top 100 hours of the year. This is an acknowledgement to say we should be using the same avoided costs process and values when we are evaluating all three of these and to make sure we don't claim sort of false precision with an energy efficiency program when it might be more effective to have a demand response program to meet a critical peak need.

This is primarily referring to I think better planning and making sure that these proceedings don't operate as islands and not understand the impacts of the others.

PRESIDING MEMBER GEESMAN: Okay, thank you.

MS. BENDER: Okay. That concludes my presentation then.

PRESIDING MEMBER GEESMAN: Mark.

MR. RAWSON: Commissioner Geesman, if I could just add a point on that last --

PRESIDING MEMBER GEESMAN: You need to introduce yourself for our court reporter.

MR. RAWSON: Mark Rawson with the PIER Program. The integration issue as you may remember was something that we discussed back on April 29th when we talked about distribution planning and how distributed generation and demand response are being looked at from a planning perspective by the utilities.

There has been some research that has been done by both PIER and separate research by the Department of Energy that has looked at that very point about integrated efficiency demand respond and distributed generation that has shown that when you look at these resources as a portfolio, the operational performance characteristics of each of the resources provides an opportunity to actually defer distribution upgrades that otherwise looking at the resources independently wouldn't be as far reaching.

PRESIDING MEMBER GEESMAN: Should we go to any public comment on this topic next?

MR. SUGAR: We have more blue cards if people would care to.

PRESIDING MEMBER GEESMAN: Barbara make

certain your microphone is turned oned on. Introduce yourself then for the court reporter.

MS. GEORGE: My name is Barbara George. I am with Women's Energy Matters, and I appreciate having a chance to speak to this issue.

I am concerned because as you pointed out savings do not seem to be connected to the money that we are spending, and that is in fact the case in California. We don't have a system which ties the savings directly to the amount of money we spend. I think this is most unfortunate.

Texas has a system that does tie the savings directly to the dollars, and that program is now getting 40 percent more savings than California is and 40 percent more savings per dollar, and it is primarily addressing peak load not base load.

The program is 100 percent designed and implemented by third party independent program providers, even though the system is nominally administered by the utilities.

At the time that the program was put together in 1999 and 2000, the merchant generators opposed the utilities being in charge of these programs because they felt that energy efficiency was the primary way that utilities romanced their customers, which is certainly true everywhere.

The Texas system is in fact quick and easy to set up. We could have it up and running by the end of the year if we decided to do that.

California's performances, unfortunately, even worse than the 40 percent worse than Texas. The utilities and the CPUC are now admitting that at least a quarter of the energy savings that they have claimed over the past five years never happened because the measure of savings, they were based on improper readings of certain measurements.

One of the most egregious ones is the compact florescent lights, the little curly Q bulbs. They were exaggerated by at least 400 percent, and 61 percent of the energy savings from the small business program were from CFL's. It was almost the entire upstream lighting program, most of the residential savings, and part of the large business programs.

PRESIDING MEMBER GEESMAN: Now where would I find these admissions in a documented form?

MS. GEORGE: In a documented form, the

Energy Efficiency Evaluation for 2003 Energy Express Efficiency Programs describes it in very clear detail. It is about four pages, I have it with me, and I can give it to you after the meeting.

PRESIDING MEMBER GEESMAN: If you would submit it to our docket, it would be very helpful.

MS. GEORGE: Okay, I will. Also, PG & E handed out something to the Program Advisory Group that admitted that the DER database updates which are due this August will incur further losses in their programs.

An even larger percent of the savings claims were committed not actual savings. An analysis that my consultant, Richard Esteves Asesco, did showed -- he basically just crunched the numbers from the utility reports from 2003 and showed that 80 to 90 percent of PG & E and Southern California Edison's large commercial programs were committed, not actual savings.

I do believe that the definition is pretty much the same between the CPUC and the Energy Commission. Committed means that they have said that this is money that is going to be available and they've signed up a customer, but it has not happened, or it has not been measured yet.

The CPUC has never had a system where the utilities had to say when those savings did actually occur. Now I think it is really good because they are going to fix that in the future. We are not counting those savings in the future until they actually happen.

The issues here are there are measurement issues, but then there are also program issues. I don't want to get confused in thinking that the CPUS has fixed everything because they took measurement in house. Taking measurement in the house is very important. Unfortunately there are no staff to oversee that program and for the next year.

You also have to appreciate that our energy savings programs are having very little need on reducing the need for supply side resources, so when you look at the charts, first of all, the charts are not real, second of all, they are not really on the peak. So, we are encountering programs that we are having problems. Like we are having in the Edison territory this summer, there is a discussion about there is a surprise increase in demand. I think you could read that just as well as a surprise failure in energy efficiency programs.

If we had actually been saving the amount of energy we could have been saving with this money using it on peak, we wouldn't be having these problems in Edison's territory, and we could be avoiding a lot more supply side resources around this state.

In Edison's territory, they are spending $57 million this summer just to expedite the energy savings, not one KW of extra savings in that program. They also ignored the multi-family residential sector. They are getting absolutely nothing out of that program, even though my organization showed that using the money in the multi-family residential sector, particularly for air conditioning would result in quicker more assured savings than many of the programs that were endorsed in that program unfortunately.

I look forward to working with you. I have submitted comments on energy efficiency in this past week and also on the IOU resource plans. I am also working closely with Community Choice Cities who are very interested in getting control of these programs because we don't believe that the utilities are doing the best job that we could get in California, and the situation is dire, and we really need to fix that. Thank you.

PRESIDING MEMBER GEESMAN: Let me ask you if you could summarize the differences between your perspective of a well designed program for the multi-family air conditioning sector and the one that the Edison company is conducting.

MS. GEORGE: First of all, they didn't want to do much on the air conditioning sector anyway. They did add more for the single family air conditioning this summer. They didn't have that originally in their program. They had largely lighting savings, and of course, in a residential application, that doesn't occur during the peak. The multi-family, we would certainly be in favor of more room air conditioners for apartment dwellers, more efficient room air conditioners is something that TURN has been fighting for, for about a decade, and I think it would be a really good thing to have.

You have to realize when we are putting in a central heat and air, oftentimes if we are putting that into an older house, we may actually be increasing the energy use rather than decreasing it. However, the people who are the poorest people who are the most in need of these programs probably can only afford a room air conditioning.

Other issues that have an impact in a lot of multi-family dwellings, people have said oh, how can we get the savings in because there is a split incentive, Asesco actually solved the split incentive problem by working with building owners, and if the building owner wanted to have savings in the public portions of the facility, they were required also to give access to each unit. That solved that problem very well.

There are innovative ways that we could be dealing with this sector, and I have to say that I am very unhappy with the utilities doing more and more in the large commercial and the single family applications and given multi-family folks less and less. They have already gotten much less than they should have, and that is usually one of the line items that doesn't get spent at the end of the year.

Another thing that happens with utilities is that at the end of the year they advertise big super sales rebate programs and they give twice as much money for instance to a small business for air conditioner or a lighting program that they -- you know, the rebates just go up, and that has been happening across the board in California for the last couple of years. They are just shoveling more and more money out the door. As we are putting more and more money into these programs, we are getting less and less out of them.

PRESIDING MEMBER GEESMAN: You have focused on peak savings in most of your comments, and when this topic came up a couple of weeks ago in our workshop, and I think you were there --

MS. GEORGE: I was on the phone.

PRESIDING MEMBER GEESMAN: You were on the phone, I'm sorry. I asked Sheryl Carter from NRDC how she would strike the balance between program design for peak design and programs designed for energy savings. I pointed out the obsession that the state has had the several years with the operational difficulties that we have meeting peak load, and unfortunately, it would appear that we will continue in that particular dilemma for the next several years at least.

At the same time, to the extent that

global climate change issues have taken on much higher profile, oftentimes, base load savings can have a much more direct impact on the reduction of greenhouse gas impacts. Sheryl indicated, well, you need to strike a balance. How would you strike that balance?

MS. GEORGE: I don't think when you are reducing base load, you don't have an opportunity to rachet those plants up and down the same way that you do with peak resources. One way I would strike that balance is to put a whole lot more solar panels all over the place. That would certainly be one way to deal with it, but in the energy efficiency sector, you just could pay more for the savings at peak hours. That is one of the ways -- the way the Texas works, it is called a "standard offer" and you put the money into a particular pot. You say here is the small business program or a large business program, I am going to pay this much for savings. You could make it a finer distinction, which they do in Texas in some programs is pay more for savings at a peak hour.

Then you put the money on the table, and then the independent program providers are able to decide how to make the savings occur. That gives you a tremendous amount, more innovation, more locally responsive programs. There is a huge infrastructure development, the energy efficiency infrastructure in Texas is something like 14 times the size of ours as far as independent programs.

PRESIDING MEMBER GEESMAN: Thank you, Barbara. Commissioner Pfannenstiel.

COMMISSIONER PFANNENSTIEL: Yes, thank you. Ms. George, I haven't had a chance to look at your written comments. In your written comments, did you either describe or give references to a description on the Texas program that you are in favor of?

MS. GEORGE: Yes, we have filed extensive -- this was the Women's Energy Matters Coalitions proposal for energy efficiency system in California that we filed comments on all last year. You can also go to our website, womensenergymatters.org, we have a lot of the documents on the website too.

COMMISSIONER PFANNENSTIEL: Fine, thank you.

MS. GEORGE: You bet.

PRESIDING MEMBER GEESMAN: Gary

Schoonyan, Southern California Edison.

MR. SCHOONYAN: Thank you, Commissioner, Gary Schoonyan, Southern California Edison. I was just going to make a few observations, and I think I will also follow up and at least as somewhat of a -- I am not an expert in energy efficiency, but try to address the previous comments that were put forth.

First, my observations. One of the things I think is what the Commission did, and I think that it was alluded to be Sylvia was a decision that basically put utilities in the administration role for a three year period. This was something that was greatly lacking over the last many years.

One of the reasons that energy efficiency and these sorts of things really didn't take hold as well as they could have during the late 90's and the early 2000's, it was like an inner-city bus ride with regard to these one year commitments, who was in charge, who wasn't in charge. It was very difficult to do longer term energy efficiency planning. With the three year out of the Utilities Commission, we are hoping that will rectify that concern.

Another thing I wanted to make an observation on, and I have made it before, I think actually in response to a question of Commissioner Pfannenstiel some time ago is that there needs to be a consistent approach to basically valuing the various demand side alternatives, not just energy efficiency, but also the demand response.

It needs to be consistent in terms of how program administration is done, how resource planning is done, and how utility operations or ISO operations is done.

We presently have a fragmented approach I think you are all aware of, and it is causing confusion as to what is there or not there for the purposes of operations, planning, and program design.

The final observation has to do with -- it sort of piggybacks off some of the last comments or at least in the direction that Sylvia was making is that to the extent that we try to get better information with regards to what the program effectiveness is, and doing that requires customer data, it is hoped that the Commission will honor the customer confidentiality aspects of that data in basically using it.

With regards to the comments that were just previously made, I want to point out that if you take a look at the man reduction type programs, Edison surpasses every other utility in this particular state. We have I believe it is around over -- it is close to 1,200 MWs of demand reduction programs via interruptable tariffs as well as the A/C cycling program which have helped, particularly the A/C cycling program late last week in mitigating some of the peak demand affects in our service territory.

There was a comment about us not being energy efficient enough because our load is growing. I think if you talk with Lynn in your demand forecasting department -- I mean we've had tremendous load growth. Where the load growth has been is out in the desert involving homes in many instances or 2,000 or 2,500 square foot, so there are large demand increases as a result of the unanticipated large growth within our service territory in the hottest parts of the service territory.

I think it is inappropriate to equate us missing the load forecast with our lack of doing energy efficiency going forward.

With regards to that, and I'm not familiar with the lady that just talked, but to the extent that she has good idea and has proposed them, I am sure she has it sounds like at the Utilities Commission and elsewhere, we are not opposed to good ideas.

We want to get the biggest bang for the buck with regards to energy efficiency, I think just like everyone else does. So, with that, I close my comments.

PRESIDING MEMBER GEESMAN: Gary, as it regards the common definitions and an integrated approach to counting the benefits from these programs, Sylvia's presentation suggested that those issues should be resolved by the CPUC by the end of this year. Do you share that optimism?

MR. SCHOONYAN: They will have I would anticipate a decision by the end of the year, but like any sort of -- and hopefully it will be a reasonable decision on all fronts and takes care it, but typically practice -- what ever decisions come out, it takes a period of practice and implementation to refine those things and to really --

PRESIDING MEMBER GEESMAN: Yeah, I'm not

so much focused on the content of the decision, but is the calendar of the decision and at least it is hoped for all inclusiveness consistent with your understanding?

MR. SCHOONYAN: That is my understanding.

PRESIDING MEMBER GEESMAN: That would address differences with the ISO method of calculation as well?

MR. SCHOONYAN: I'm not 100 percent sure on that, Commissioner.

PRESIDING MEMBER GEESMAN: Okay, thank you.

COMMISSIONER PFANNENSTIEL: Gary, do you find that the existing guidelines or maybe the proposed guidelines give Edison enough flexibility in being able to move money among programs to meet, for example, summer peak, new information, new technologies, whatever, do you have that ability?

MR. SCHOONYAN: I think with regards to the funding flexibility, I believe we do. Where I think there is a bit of a concern is when new ideas and new approaches to energy efficiency come forward, it takes awhile to get those approvals to go forward with those particular types of efforts.

PRESIDING MEMBER GEESMAN: Thanks very much. Manny Robledo, Southern California Public Power Authority.

MR. ROBLEDO: Good morning. I'll just offer a few remarks. We haven't had a chance to produce written comments. California Municipal Utilities Association will be providing written comments made on behalf of all the Muni's.

My name is Manny Robledo. I work for Southern California Public Power Authority. We represent most of the municipal utilities in Southern California, including Los Angeles Department of Water and Power who may be submitting comments on their own.

In general, I would just like to respond to a few of the issues raised in the report that seem to indicate that municipals aren't doing as much as they could be doing with regard to energy efficiency or renewable resources.

That is just not the case. We at SCPPA coordinate the activities of the members, and we have monthly meetings of the managers of the public benefits committee managers and also the resource planning managers, and we have a commitment to renewable resources and energy efficiency because they are good for our customers.

As consumer-owned utilities, our customers are our shareholders. When we take monies and allocate to these areas, it is for their benefit. That is our overriding criteria that we use in the development of programs.

Having said that, since the advent of AB1890, we've actually spent $700 million on public benefits programs, not including the additional monies that have been spent on renewable outside the public benefits programs because some of our members actually support the renewable portfolio standards from their energy procurement areas and not out of public benefits.

So, we've made a substantial commitment. We, at SCPPA, coordinate annual report of all these activities that is published on our website and details each one of the programs and activity along with those.

In addition to the money that we've been spending, with regard to renewable resources, we feel that our track record is actually surpassing on a per rata basis what the investor-owned utilities have done. Reading through the report, an example from the RP's that were issued by Southern California Edison by the investor-owned utilities essentially, it seemed like the numbers were relatively low as far as the commitments that were made.

One number that comes to mind is 142 MWs out of a 17,000 MW system which is less than one percent versus in combination of the contracts done through SCPPA, which we have had three joint projects that have had more than five municipal utilities participating, and the ones done independently by Los Angeles Imperial Riverside and the like, we have actually added 470 MWs of commitments and renewables which is about a five percent of our load.

So, I think the implication is we are not doing enough. That five percent takes us from a three percent starting point to eight percent on our way to 20 percent. A few comments that we've received from the developers in doing those renewable contracts is that prefer doing business with the muni's because we can sign up for 20 year contracts and make a local commitment of our policy makers and not have to go back and revisit it through supplemental energy payments or other things that go along with the IOU process. We have had quite success in that area, and it is going to continue.

I'll just touch on a couple -- I know we haven't talked about them yet, but the other areas, the loading order, distributed generation. We feel that deliverability is important for resources, and we do support distributed generation. Of course the same criteria holds for customers. It has to be good for the customer, so we would hope that the customer doing it would receive higher thermal efficiency and reduction in their bills overall.

The other type of distributed -- is there a time limit?

PRESIDING MEMBER GEESMAN: That's somebody on the telephone.

MR. ROBLEDO: Our other commitment to distributed generation would be deliverability of resources, and our members have added significant resources since the power crisis in the form of development of 6,000 turbines within their distribution area that would provide reliability and not rely so much on the grid, as well as baseloaded resources, so we do have a commitment to prevent our efficiencies and reduce our emissions.

Magnolia is our latest power plant in the City of Burbank, it is in a load center. It is serving load that even though it doesn't follow the regular definition of distributed generation as an owner, but it is doing all of the things to reduce congestion and relieve the transmission grid.

Finally, along those lines with I guess the fourth area of the loading order would be the fossil fuel clean energy, clean fossil fuel. We have added a significant amount of I think close to 2,000 MWs as the California muni's.

Los Angeles has been repowering their fleet and retiring old steam boilers and replaced them with combined cycle state of the art generators, so we are doing our part to reduce emissions and use those fuels well.

With that, I would be glad to answer any questions.

PRESIDING MEMBER GEESMAN: We were urged at our workshop two weeks ago by Ralph Cavanaugh from NRDC to greatly improve the metric by which we evaluate energy efficiency programs and renewable programs to promote a better comparison between the efforts and accomplishments of the municipal utilities and the investor-owned utilities, and Ralph left no real uncertainty as to his view that the municipal utilities had lied quite a bit in that regard.

I would ask that in your written comments and if you would encourage CMUA to do the same to address that question of what type of reporting system or public metric would better promote an objective comparison and provide greater confidence on the part of state policy makers that the municipal utilities were doing their share. I think those kinds of comments to us would be quite helpful.

MR. ROBLEDO: Okay, we will certainly do that in the written comments. Just in general, over the past two years, we've been tracking our performance, not through third party M & V, save for Los Angeles, Los Angeles does have the third party M & V program that they operate, but in general for Southern California muni's, we've started a subcommittee to standardize our engineering estimates that we use for each program and we've actually reported in aggregate the savings of our members. We haven't reported them individually, and that is coming, but for the past two years in our report, we've had actually results that go along with the money.

PRESIDING MEMBER GEESMAN: Any material that you could submit to our docket would be quite helpful.

MR. ROBLEDO: Okay, thank you very much.

PRESIDING MEMBER GEESMAN: Okay, why don't we move on to demand response unless there is any other public comment on energy efficiency.

(No response.)

PRESIDING MEMBER GEESMAN: Okay, great, let's go to demand response then.

MR. HUNGERFORD: All right. I'm David Hungerford, good morning. I'll be covering demand response.

This first slide just shows the order of the topics I'm going to discuss. They are a little bit different order than the slides. I have challenges right before my recommendations, and we discuss measurement and verification issues, our D issues, before that.

I need to start with some errata that were picked up by a careful reader, and we are happy to make these corrections. The first one regards a graphic figure 13 in the report, there was an error in one of the terms that were used. The text you see below the graphic is the correct text. Figure 13 shows the fractional load reduction estimated, that is this is an impact slide, and the term that was used there originally was elasticity. This slide does show an elasticity, but instead it shows the percentage impacts from an experiment with small customers, showing the impacts of a critical pricing style rate. It also gives us an opportunity to show the magnitude of those impacts using different estimation methods. So, we will move on from there.

The second errata regards the figure 14. Figure 14 and Figure 13 appeared together in the text, and there was a possibility that people could interpret those slides to mean that the data were analyzed in precisely the same way. In fact, the data were analyzed using a couple of different methodologies, and we just wanted to point out the distinction of those two graphs and the magnitude of the KW estimates, and the percentage impact estimates are not directly comparable. It has to do with the correction methodologies that were used to correct for a form of bias present in the analysis that they were attempting to correct for.

I will move on to the beginning of the presentation, and we want to talk first about the demand response goals. They were originally set in the demand response proceeding in 2003, and they called for incremental progress towards a total of five percent demand response, five percent of system peak for year 2007.

In December of 2004, procurement decision directed the investor-owned utilities to include the demand response goals in the resource stack, and so at that point, the Public Utilities Commission made the determination that the demand response goals set in the demand response proceedings should be considered as the same goals that were designed to provide resources in thinking about stacking the resources for procurement purposes.

The January 2005 decision in the demand response proceeding clarified that only price responsive programs and tariffs and not reliability programs would count towards meeting the demand response goals.

PRESIDING MEMBER GEESMAN: Why is that distinction drawn, Dave?

MR. HUNGERFORD: The original demand response proceeding had in mind the idea of encouraging the utilities to move towards to price responsive programs, programs which the customers were responding to a price rather than an action taken by the utilities to reduce load in response to an internal price, but a price that the customers never saw.

The reliability programs, interruptable programs, air conditioning cycling programs, and the like, back up generation emergency programs, had been in existence for a long time, and it was not the intent in the demand response proceeding to simply take the numbers that were available, the MWs that had already been achieved through those programs and count them towards this new goal.

PRESIDING MEMBER GEESMAN: Okay.

MR. HUNGERFORD: Setting a goal for program development and measure progress in a program and setting a goal that resource planners and engineers and the ISO can depend on as resources in a particular emergency situation or a particular supply situation, there are some different needs for those two uses.

In making the same goals, the goals for those two different purposes, which the PUC did over this last winter, creates a couple of issues which may need to be resolved.

I've broken this down and tried to conceptualize how to think about these goals by coming up with three different terms. One I called enrolled MWs that reflects the maximum possible demand response available from customers enrolled in the programs.

One could think of it as if a business decides that they have 50 KWs that is the total possible demand response they could provide under any circumstances, the total of the number of lights that they can turn off and the air conditions that they could cycle off, or the freezers they could cycle off, or something like that. That is the number that tends to be reported for the demand response goals.

However, because it is a price responsive program that they are involved in at a particular price level, or during a particular circumstance, they may not provide all of that load reduction in any particular circumstance or on any particular afternoon, so it is analogous to technical potential.

There is a maximum you can get, but then there is a number that is closer to what you might actually get, and then adding up all of the customers and then looking at that over time, you get a different kind of estimate than that maximum number would tell you, although that maximum number is related to the total number of demand response that you might receive at any particular time. It is not necessarily the measure that you would want to use in resource planning.

Demonstrated MWs, it would be actual performance data, and right now we have very little actual performance data. These programs have been in place since late 2003 and early 2004, and over that time, those programs have changed about every eight or ten months due to new filings with the Public Utilities Commission. The utilities have been trying to work with the programs to make them work better, to respond to customer concerns, to increase enrollment.

Customers have been learning about how to respond to these programs, and the fact is, in

2004, the summer was relatively cool, and the programs were primarily called on a test basis rather than on a real need basis, and thus the data we have on actual performance is very thin and doesn't have much of a history.

While that would be the preferred method for estimating demand response in the future, right now we are still at that early stage where we don't have a whole lot of data on it.

MS. JONES: Dave, can I ask about the existing programs?

MR. HUNGERFORD: Sure, go ahead.

MS. JONES: You had some tests done, was there any price response involved? Were there any different tariffs?

MR. HUNGERFORD: Oh, yes. For instance, the critical peak pricing tariff is a time of use style tariff that has a floating critical peak period which can be called a day ahead.

MS. JONES: I mean in existence today or when we did the testing on the programs in '03 and '04, was there a critical --

MR. HUNGERFORD: Yes. The test events were that the customers were called and said today or tomorrow will be a critical price day, you will be charged the higher price tomorrow. It is just that it was not triggered by necessarily an ISO alert or another event related to the actual system conditions. They were called in so that the utilities could test what kind of response that they were getting.

There were some actual events in 2004, but most of the events that were called were test events.

MS. JONES: Thank you.

MR. HUNGERFORD: Then there is something that I am calling expected MWs, which is a combination of enrolled demonstrated and the best estimates that the utility resource planners could put together on what they actually expect to get from these programs in the very near future.

Some of that is a little bit of educated guess work and seat of the pant thinking, and some of it is based in reality. This number is the one we expect to be the closest to the actual response. We will see.

To illustrate, this table represents, I've listed the 2004 goals, the revised 2004 goals, the Public Utilities Commission revised the goals, the programs got started enrolling a little late. They didn't start until July of 2004, or some of the programs were not operating until July 2004, so the administrative law judge issued an order where the goals were revised for 2004 only, but were not revised on into 2005, 2006, and 2007. You see those and those revised goals were basically set at what the utilities believed they could meet for summer 2004.

The two numbers you see in blue on the right hand side, the enrolled MWs in April of 2005 and the expected MWs in April 2005 represent what the utilities reported they had enrolled in the program on the left side and that best estimate based on the performance data that we have, reports from customers. For instance, one utility reported to us that a number of their customers did not respond during the test event because they didn't want to reduce their operations. It reduced the product that they were putting together at that time, but if it were a real emergency or if it were a stage two alert and the system were very much stressed, that they would in fact contribute load reductions at that time, even though they were charged the higher price.

COMMISSIONER PFANNENSTIEL: David, help

me understand this a little bit then. The right hand column on the table is what the utilities, this 369 MWs total, is what the utilities believe they will be able to get from these customers in a real emergency, is that what we are saying if it really gets called upon?

MR. HUNGERFORD: That's right.

COMMISSIONER PFANNENSTIEL: That they think they can get 369 MWs?

MR. HUNGERFORD: This is what they are confident, very very confident that they can get in an actual emergency and are willing to procure based on this number or reduce their procurement by 369 MWs. They are not willing to reduce their procurement by 556 MWs.

COMMISSIONER PFANNENSTIEL: I am wondering about 1,203 MWs which the PUC apparently has told them they should be able to rely on by I assume summer of '05, is that where the 2005 goals come from?

MR. HUNGERFORD: Yes.

COMMISSIONER PFANNENSTIEL: What happens? The PUC says 1,200 and the utilities say 370, and is there then best efforts next year or something fundamentally wrong with the program?

MR. HUNGERFORD: You have anticipated some of my later slides. If you would be willing to --

COMMISSIONER PFANNENSTIEL: Great, if you could answer those questions further on, I'd be glad to hold my questions.

MR. HUNGERFORD: I address that adequately in the later slides, but, yes, you've identified the issue that I hope to illustrate here is that there is this disconnect between the use of these numbers as a measure of program progress and the use of the numbers for procurement purposes.

PRESIDING MEMBER GEESMAN: In business school they say that the dogs just aren't eating the dog food.

MR. HUNGERFORD: Do they?

(Laughter.)

MR. HUNGERFORD: That is one way to look at it, but I think that one of my later slides will help a little bit on understanding some of the issues we are facing.

I wish my eyes were better. I am sorry, I write too small. I write like I did ten years ago, and now I can't read it anymore. This slide identifies some of the measurement and verification issues. We are feeling a very strong lack of data here and some problems with the methodologies that have not yet been resolved.

This first bullet, the idea that we need to develop a good methodology for valuing demand response points to some of the discussion we had during the efficiency portion of this presentation.

Right now in efficiency, we have a standard practice manual that was put together a number of years ago that provides a number of methodologies for testing the cost effectiveness to distinguish between the relative value of different types of efficiency programs.

Those protocols can be used for demand response, but they don't really fit very well, it is a round hole, square peg problem. One of the things that needs to happen is that methodologies and protocols need to be developed to measure the cost effectiveness of demand response measures so that those distinctions can be made so that with the limited resources that are always available to invest in these things, one can distinguish between whether to put that money into a particular efficiency program or into one demand response program over another program.

So, that is something that we want to move towards and currently, demand response proceeding is moving towards that. There has been some contract money let to begin the development of these measures, and there will be some work being done on that this fall. I anticipate it also will be discussed and dealt with in the next decision that comes out of the demand response proceeding.

The second bullet is something that I mentioned before, we just have a lack of experience with these price sensitive demand response programs, and there is some uncertainty as to how much of that demand response can be counted on, and resource planners have to be conservative when they are making their procurement choices, and they tend to want to back down their estimates of what they are willing to accept from any kind of new program, including demand response, to something that they know that they can count on without question.

Until we have a better track ready and or data and more time and experience under our belts, we are going to see this divergence between what we should be able to get and what we think we might be able to get and what resource planners might be willing to trust.

Here we come to the integration issue again, integration of demand response and efficiency is good for customers, but difficult to measure and assign attribution for the cost effectiveness testing.

First of all, I want to back up my messengers point. This need for integration is a customer perspective issue. Customers don't want to be approached by people from the utilities or private parties for three different types of programs saying you need to invest in efficiency here, and we would like you to invest in demand response over here, and distributed generation or renewables over on the other side.

The utilities and the customers would like to see an integrated approach where there is sort of a one stop shop for putting together the best sorts of programmatic help that a customer can get all in one package.

To that extent, the utilities have proposed and the PUC has approved the move towards that in integrating demand response and energy efficiency programs. The way that will work in the future is that customers will be approached and they will be provided audits and a series of more detailed audits depending on their potential and a package of programs will be put together if they are interested in participating.

MS. JONES: David, in relation to the item that you've just listed here, were there surveys conducted of the customers? How did you come to the conclusion that they --

MR. HUNGERFORD: That was part of the first year evaluation results in customer interviews, both the program participants and large survey program non-participants by Quantum Consulting. Quantum surveyed both customers, and they survey account representatives at the different utilities and program managers at the utilities.

All three of those data sets, the responses tended to push towards this direction, that these artificial walls were not something that we see in the proceedings and the way we approach these problems is not what the customers see. The customers see it as one big package of reducing their energy consumption and maximizing their benefit under whatever available tariffs there are.

MS. JONES: Thank you.

PRESIDING MEMBER GEESMAN: Which customers are we talking about?

MR. HUNGERFORD: In the evaluation, we are talking customers over 200 KW.

PRESIDING MEMBER GEESMAN: Okay, but then you said something about the demonstration program. Were you talking about large customers or the residential pilot that you ran for --

MR. HUNGERFORD: I only referred to the residential pilot with those first couple of drafts. Right now we are talking about large programs because that is the only place we are doing demand response programs. We had an experiment with small customers.

The next bullet, we need to include demand response more carefully into Energy Commission forecasting methodologies, and that will require a more detailed understanding of customer response under various conditions.

We will need to update our forecasting methodologies to include hourly load data from customers who are investor-owned utilities as it becomes available. That is a challenge in front of us.

We need to improve our understanding of customer inputs as input policy decision making, and this is where I do broaden these issues to include small customers. We need more detailed information, more understanding of customer impacts, and we need to provide that information into the decision making process so that the decision makers can be sure that they are making decisions that work and choices that work.

Research and development issues. In moving towards default dynamic rates, which we are moving towards for large customers, we will to develop support programs, including education, technical assistance, and technology incentives to aid customers in adapting to the renewed rates.

This is a combination of this integrated approach as well as a -- this is a call to say that we need to move forward on these things quickly. The large customers in the beginning of the proceeding that considered default dynamic rates for this summer and then decided to push that off and push for summer of 2006 or 2007 and new applications recognized that one of the big issues for customers was learning about the new tariffs that were coming down the road, figuring out how to adapt to the new tariffs, and being educated on how to respond to these new tariffs.

It is a large task, and it is going to take time to bring customers up to speed so that they can provide demand response under the new tariffs. Otherwise, the customers run the risk of not being able to respond or not knowing how to respond or making operational changes that are not cost effective.

PRESIDING MEMBER GEESMAN: If we are talking about large customers --

MR. HUNGERFORD: That is what we were talking about right here.

PRESIDING MEMBER GEESMAN: Is it clear that each of them has a comparable level of capability in responding?

MR. HUNGERFORD: Oh, no, of course there is a distribution of response capability across all customer groups.

PRESIDING MEMBER GEESMAN: Tell me why we should be optimistic that this program is going to work even with better measurement and evaluation capabilities or more support programs or education or technical assistance.

If I've got a restaurant, how do I shift my demand away from its existing load profile? Customers want to eat at dinnertime, I can't really sell them on midnight suppers.

MR. HUNGERFORD: Yeah, we catch shift to weekends and mornings and evenings. That is an issue that needs to be addressed, and the impacts of the programs for those particular customers just like efficiency programs don't apply to all customers. Those we need to understand that better. We need to understand those customer impacts better, and we need to develop policy responses that treat all customers fairly.

COMMISSIONER PFANNENSTIEL: David, before we leave that example, and I am still really hung up on this whole program design that doesn't seem to be working at this point for the restaurant that Commissioner Geesman just mentioned, for the few hours per year, they might be able to make some accommodation or pay the higher prices for a few hours per year, and so or them, they might be willing to go on this rate on a dynamic pricing rate voluntarily because they

may say for a few hours a year I can make it work.
Of course, every customers by SIC or geography or some combination will have different means of evaluating it. You know, I am still looking at the numbers where the utilities are able to sign up. I think you had 555 MWs enrolled out of a very large number of MWs in the customer classes that are currently metered to do this. I am trying to get, I think, where John was also is it a program design issue that is not allowing these prices to be reasonably attractive to customers.
If that is so, when you move to default pricing, I understand that would imply that everybody then, all of these customers who are metered appropriately, would be on a then critical peak pricing rate unless they opt out of it.
MR. HUNGERFORD: That's correct.
COMMISSIONER PFANNENSTIEL: Is that how we are going to get sufficient number of at least enrolled and then we need to work on the actual responses, is that the programmatic change that we think will make the big difference?
MR. HUNGERFORD: I am trying to see if the answer yes applies to everything you said, and

I think it does. I think it does. I think that is the direction we are trying to move.

Let me address the program design issue that you first brought up. Yes, one of the reasons we have what appears to be or to be a relatively small amount of demand response from the current voluntary programs was one of the restrictions that were placed on the programs at the beginning. That was that the tariff designs and the program designs needed to be revenue neutral within the customer class, meaning that the utilities could collect no more or no less revenue from the entire group of customers from the change, from the tariff change.

What that meant was that it minimized the potential bill impacts for the customer on the downside. For a customer who moved on to a CPP rate, they might see a relatively small bill increase if they did not change their behavior at all, they did not provide demand response between two and five percent of their annual bill, which for a large customer is a significant amount of money, but in terms of percentages, relatively small.

By the same token, the upside was also

limited in that there was a very small possible bill savings available from what could be relatively large operational changes and/or investments in energy management technology or changes in equipment they would have to purchase.

The investment in time and effort was seen by a lot of customers who would be interested in this type of thing, the benefit was seen to be too small to make that investment right now, so there was a wait and see attitude among a large number of the customers, the non-participants that were interviewed.

They were aware of the programs, they saw some possibilities for the programs, but there wasn't enough benefit to make them jump, and there was a little bit of uncertainty this first year programs, the parameters of the programs would change in response to customer needs and in response to Public Utilities Commission's perception of what was going on with the programs. They wanted to wait and like diffusion of innovations theory, the first people who jump on something like this, are relatively small number of people who are interested in innovating and see a direct benefit for themselves at the time.

Out over time, more customers will come into the program, so we are still at the low low end of the diffusion curve.

PRESIDING MEMBER GEESMAN: All of that was attributable to the revenue neutrality requirement across customer class?

MR. HUNGERFORD: It was attributal to the relatively low magnitude of potential benefit and the uncertainty that customers saw in how stable the programs and programs and tariffs were at this time. That is what they told us.

PRESIDING MEMBER GEESMAN: Okay, I can accept low magnitude, and I can accept uncertainty as inhibitors to program participation. Where I am having a hard time connecting the dots is that imposing a revenue neutral requirement across a broad customer class produces that inhibition as well.

MR. HUNGERFORD: That is why the revenue neutrality requirement was what contributed to the tariff designs and program designs that made the magnitude of the savings and the magnitude of the losses relatively narrow.

PRESIDING MEMBER GEESMAN: Which would suggest that most of the customers across those broad customer classes had similar load profiles?

MR. HUNGERFORD: No. They have very dissimilar load profiles. There are customers over 200 KW range for everything from the very largest customers, refineries, Portland cement makers to WalMarts, and hospitals, to shopping malls, to small manufacturing facilities, and assembly industry. There are a wide range of customers -- to large agricultural customers, a wide range of industries, a wide range of needs.

PRESIDING MEMBER GEESMAN: Which would then suggest that under the program design, there should have been winners and losers that would enjoy benefits and burdens of significant magnitude.

MR. HUNGERFORD: One would think, but the tariff designs ended up being to where -- sure, there were people out in the tails of the distributions or a small number of customers out in the tails that could have been huge benefitters and huge losers, but most of the vast majority of customers were within two to five percent in terms of their potential for these things.

You have to factor in the combination of uncertainty --

PRESIDING MEMBER GEESMAN: I don't want to go to uncertainty, and I don't want to go to low magnitude. I want to zero in on revenue neutrality because if that is the source of problem or a significant contributor to the source of the problem, how do you propose to cure that?

MR. HUNGERFORD: I don't have a particular proposal, I know that the assigned commissioner and the administrative law judge and the demand response proceeding have been moving towards including the demand response rate designs in the general rate case cycle and trying to get that put in to the general rate case cycle, so that the next time as the utilities reach the next time where they are litigating their general rate case, that these issues are considered and this tying to the previous revenue requirement that was conceived without consideration of these programs could be considered fully in that proceeding.

PRESIDING MEMBER GEESMAN: I suspect that if you are concerned about magnitude of benefit, you are not thinking about making it a revenue loser across a certain customer class. If you vary from revenue neutrality, I would presume the only direction you are likely to go is to make the program a revenue enhancer across a particular customer class?

MR. HUNGERFORD: I don't know, I don't believe so.

PRESIDING MEMBER GEESMAN: You've got three choices, Dave --

MR. HUNGERFORD: I understand.

PRESIDING MEMBER GEESMAN: -- it's neutral, it loses, or it gains --

MR. HUNGERFORD: That's true.

PRESIDING MEMBER GEESMAN: -- revenue. You say neutral doesn't work --

MR. HUNGERFORD: To the extent that procurement costs would be reduced by then response coming on line and reduce procurement needs, then costs would be reduced over all. So, the revenue requirement would be less.

COMMISSIONER PFANNENSTIEL: John, it is possible I guess that they could design, the PUC could design a rate such that the customers on the rate would shift enough of their or reduce their usage of the critical peak time more than was anticipated, and, therefore, their utilities would recover fewer revenues than they had expected. I mean that --

PRESIDING MEMBER GEESMAN: Yeah, I agree that is possible, and I would think that if that were possible we would have seen something like that with a revenue neutrality requirement. I am having a hard time understanding why revenue neutrality created such a large problem.

MR. MESSENGER: Commissioner, this is Mike Messenger, I would like to add a couple of other considerations here to this question.

I think the number one factor that contributes to the low customer participation in this particular program is inertia. Most industrial customers have spent years learning how to refine and respond to an existing set of tariffs, and unless there is a real winning proposition, and I believe the report says unless they can save something like 10 to 15 percent on their energy bills, they are not interested in spending the time and effort to figure out how to qualify for the program and get the incentives.

In terms of the revenue neutrality issue, the reason that is important is when you impose a revenue neutrality constraint on any particular tariff, it means that you can't send the pricing that represents the actual cost of delivering electricity at that particular point in time because you are uncertain about what fraction of the customers are going to respond and what fraction of the customers are going to do nothing.

Revenue neutrality in this sense meant we want you to accept as a basic assumption, there will be no response from anybody. Now design us a tariff that is revenue neutral. When you take that initial assumption, no response from anybody, that is what messes up the problem because you can't reflect the real costs.

For example, if the price on peak was 50 cents, the revenue neutrality constraint may take you to bringing that back to 35 cents or 30 cents because you can't violate -- you don't have any experience to project what the actual net effect is going to be across all of the customers when you introduce this tariff.

That is the initial --

PRESIDING MEMBER GEESMAN: That is the source of your problem, isn't it, the inability to assume a participation rate or a responsiveness. It is not the revenue neutrality, it is the inability to make the assumption I believe that creates your problem.

MR. MESSENGER: The inability to accurate project if we were to offer this program to a 1,000 customers and 500 accepted, are they going to have a five percent effect on load, a zero percent, or a 15 percent effect on load. Without that, the more conservative presumption was assume revenue neutrality and no effect cross customers.

The only solution to this from my perspective is to stop trying to create voluntary programs that mask price signals, and instead, send everybody the right price signal and give them the option as they have in New York and other states to opt back to some other set of pricing that better fits their business needs.

They can buy hedges, they can buy flat rate products, they can buy a variety of things, but I think the problem to date, the reason why we haven't met the goals is that we haven't yet been willing or having enough data or evidence to actually send the real price signals. Once those signals get sent, you will see some reaction, particular in the industrial sector because it is their business, and then we won't have to have voluntary sign ups, everybody will respond on their on to the price signal in whatever ways they need to and seek assistance when they truly don't have, for example, and engineer on staff or someone could advise them about what their options should be in face of that tariff.

To sum up, the reason why a lot of these goals are not being met, at least right now from my perspective, is we had presumed that by calendar year 2006, most people would be on default pricing, and that pricing in and of itself would have gotten to the MW goals. What we have is the results of two or three years, I guess only two years, of trying to sign people up voluntarily onto a tariff which as David said doesn't make a lot of sense for most customers because they can't see enough up side or downside to stay off the initial position, which is the one that they are used to which is inertia.

PRESIDING MEMBER GEESMAN: In the face of an anticipated crisis in Southern California this summer, we came up right to the edge of I will call it a swimming pool, others would call it a cliff, chose not to jump. Why is next year or the year thereafter likely to be any different?

MR. MESSENGER: I can't judge the

political reasons for why we either chose to jump or not jump, but let me just tell you from an analytical perspective, we hope that we will have a lot more data about how people have actually responded to these rates and a lot more joint understanding of what the prices are at various points of time on an hourly basis with the utility rate design people.

In my judgement, one of the reasons why both the CPUC and to a certain extent the Energy Commission, to the extent we are involved in that decision, didn't go for the default is that there was big disagreements between the rate design people about what specific tariff should apply and how to apply it.

David has had a set of workshops where they are working towards agreement now and basic principles how should we allocate costs, should there be a demand charge, etc., so I am hoping there will be more agreement from the technical community about what is appropriate as well as more education that I think people from the Silicon Valley Manufacturers Group and others are doing with customers about what their response capabilities are in response to a tariff.

PRESIDING MEMBER GEESMAN: Even though enrollment for 2005 hasn't really climbed very much beyond the 2004 goals, you still expect to have an increased amount of valuable data as time passes?

MR. MESSENGER: Yes, because we are doing more monitoring, and I believe we are collecting more data, both from small customers as well as large customers about what their response is to the tariff. I think the institutional issues are probably bigger than the experience issues.

Rate design is probably the most complicated topic, at least that I know of at the PUC, then there are all kinds of different people who are skilled experts in making sure that their client gets the best particular outcome, and I think that is particular true in the industrial sector.

If you ask me to make a guess, I would say the guesses still are only 50/50 about whether when the data is in front of the decision makers in the later part of this fall whether they will actually go to the default tariff.

PRESIDING MEMBER GEESMAN: Thank you.

COMMISSIONER BOYD: Mr. Chairman, this colloquy with Mike has been very revealing and kind of brings to a head a lot of discussion that has been taking place here this morning in my mind, and first generated by a reading of the report which I said earlier at the beginning was comprehensive and well done, but looking at this from kind of a 30,000 foot level as we have to as policy makers once in a while, this goes a long way to explaining why over the last couple of years in every energy action plan meeting we've had where the supply and demand discussions take place, and there is a general criticism made by some of even our staff, not assuming much in the way of efficiency and demand response, and the feedback being that, well, job one in the energy action plan as well as the IEPR, has been efficiency.

Job one, in a fraction, has been demand response, and we move on down the list through distributed generation and what have you. We've obviously been encountering all of these issues.

We can't have the time back, and I am glad to see all of this put out on the table as reasons why in these other forms, we've had some exchanges, sometimes with a few barbs in them, but no meaningful discussion behind those other public discussions as to the reasons we are not able to accomplish this.

Like I said, you can't have time back, we have to move forward, but we had a lot of discussion this morning about programs integration or program design, and just now identification of need for R & D to support this, and I guess I am kind of depressed over the fact that it appears that it is going to take a long time to realize what have been the highest possible goals, and this doesn't mitigate very quickly the problems that you just brought up about approaching a precipice a couple of times this past week in Southern California.

Nor does it offer me any great feelings with regard to the future to realize benefits from these programs and to avoid a lot of the other consequences of having to put more iron on the ground which I am not too wild about. This is maybe a comment to make at the end of a proceeding, but we seem to have been approaching this, and I guess it kind of fits the moment. I am concerned.

COMMISSIONER PFANNENSTIEL: I'd like to offer just an observation also. Demand response is very high up in loading order, and we said that in 2003, and we reemphasize it. I also know that there has been an incredible amount of analysis and research that has gone on in this area. I also would further observe that this is some analysis and research and discussion that has been going on for 30 years in this area.

Looking at the goals that are incorporated in the report, they are ambitious goals and meaningful goals, but I am not at all sure that the way we are talking about them right now that they have any stake in reality. I don't see that anything that we've heard right now says that we are going to come close to achieving four percent of the annual system peak demand in 2006 or five percent in 2007.

I know from a policy standpoint, the IEPR policy standpoint, we really need to make sure that the recommendations that come out of this Commission going forward to the governor's office on demand response, really get to the fundamental Mike identified institutional issues, rate design issues, whatever it is going to take.

If we believe that demand response is second only to energy efficiency in the loading order, we are not there yet.

We have done a lot of work and a lot of very good work, but we need to now figure out what we need to do next and how to get there. I think we need to be really realistic about where we are going to be in 2006 and 2007.

I know, Dave, you have a slide and recommendations and maybe we need to get to that.

MR. HUNGERFORD: Thank you.

PRESIDING MEMBER GEESMAN: Thanks, Mike.

MR. HUNGERFORD: I think we were on the first bullet. So, I will just move on to the second two quickly.

We need to work on automated demand response technologies, and we are still doing that through the demand response research center at Lawrence Berkeley National Labs that we are partially funding through PIER is working on a number of these things doing a number of different technologies for both large and small customer applications.

We wish to continue moving in that direction. We need to expand even more into integrating, research integrating demand response energy efficiency and renewable applications for small customers.

I think particularly of an example of integrating the idea for a small customer an air conditioner that is both efficient all the time and has demand response capabilities, the ability to respond automatically to a signal from the utility or the independent system operator would be an appropriate type of direction to go.

PRESIDING MEMBER GEESMAN: That point frankly to my ear sounds a little bit different, perhaps a lot different to the philosophical preference that the state has appeared to have for the last three or four years to voluntary price motivated, every customer is a day trader with his thermostat focus of our demand response program to date. Am I wrong to derive that conclusion, or are we allowing the cycling programs to come in out of the dog house?

MR. HUNGERFORD: I'm not going to make a judgement as to whether the ideas that you are expressing here are wrong or right. I do believe that on some level, moving towards automated demand response, customers don't want to be day traders with their energy use. That includes large customers as well as small customers I believe. To the extent that technology improvements could help meet some of those load and provide bill reduction benefits to customers, it just seems like an appropriate place to go.

In a very crude way, a customer on a time-of-use rate benefits or a CPP rate benefits from an A/C cycling program, even if that program is not directly connected through their tariff.

Their air conditioner shuts down when the price is the highest. That is a crude way of doing it, and I think we are envisioning something a little more customer friendly and something that falls a little bit more under a customer's control.

So, I think that moving in that direction doesn't necessarily take us away from the voluntary perspective that customers facing the right prices do make choices that are in their own best interests based on their individual circumstances.

The customers who are not using air conditioning who have already chosen to reduce their load benefit by having lower tariffs because they are using less energy on peak than average anyway.

Challenges to meeting the demand response goals. I think we have covered a lot of this already. Because we have directed the programs primarily at large customers, we really only are affecting about 20 percent of coincident peak demand.

That means 80 percent of coincident peak does not have an opportunity to participate in any demand response program.

Volunteer programs have limited potential. If you don't have to sign up for a particular rate, if you are someone who is using more on-peak than average, then it is not to your advantage to join a voluntary program unless you have it is relatively easy because of the way your operation to reduce your demand on peak. It is a benefit from the program.

If you are structural winner, then it seems reasonable to go on a program where you save a little money. I think that the fact that we didn't have more structural winners joining the program with a relatively low level of response we've had is an illustration of the point that

Mike Messenger brought up a few minutes ago, that there is a bit of inertia for customers to move from one tariff to another.

They are used to it, they have a small difference one way or the other, it is not going to motivate them to make changes to do anything.

This is relatively new ground that we are plowing, and this goes to the inertia issue. Customers are a little bit skeptical of the programs. They need to see more examples of the ways other customers have responded. They want to get in on it when it becomes really good to get in on it, and they are still waiting to see if we have reached that point yet.

Recommendations. This goes back to the first part of the presentation. We need to clarify the methodology for counting MWs towards demand response goals, and either adjust the goals as necessary to reflect an agreed upon method. I don't know what the solution is or what the right methodology to use, but we need to move towards doing that, and we need to come up with a way of doing it that addresses the problems that we've raised.

We need to expand participation in large customer demand response by developing a default critical of peak pricing rates, with an option to remain on the otherwise applicable tariff.

The current decision in the demand response proceeding directed the utilities to design a default critical peak pricing rate that had an opt out option to the current rate, and the revenue requirement for the new rate was to be designed in such a way that the revenue requirement for the critical peak hours estimated at somewhere between 80 and 100 hours per year on average would be separated from the revenue requirement for the other 98 percent of the time, and/or 99 percent of the time.

If they were to come back with a tariff designed that in a hot year, they would collect more revenue, and in a cool year, they would collect less revenue, and then it would average over time based on the tariffs.

In a cool year, they might not call it critical peak at all, and we would be able to dispense with test events called for the purpose of bringing the revenue requirement back to expected.

In hot years, the customers will have

been benefitting from lower rates off peak and during peak periods on days when there was plenty of supply, and they would accepted the risk in order for that discount over a period of time where they have accepted the risk for that discount and pay more during those high periods and potentially reduce their demand on those rare times that they needed to reduce it.

The third recommendation is to expand the advanced metering infrastructure to allow all customers to participate in and benefit from demand response programs and tariffs.

The other 80 percent of the peak demand, in order to meet those goals needs to be included. I believe that concludes my presentation. Any questions -- what are the questions is a better thing to say.

COMMISSIONER PFANNENSTIEL: Dave, you've been meeting with the large customer groups for some time now and understand pretty well what their concerns are.

MR. HUNGERFORD: I am trying to.

COMMISSIONER PFANNENSTIEL: I can recognize that the idea of this rate, a critical peak pricing rate, might be sufficiently uncertain to them or frightening to them that they would like the ability to opt out of it and go back to their other rate.

Do you, though, have a sense of whether any other rates out there that customers are on are essentially voluntary? My understanding is always that the Public Utilities Commission adopts rates for customer classes, and unless they are in some ways experimental, customers are on those rates until the PUC changes them again.

Would the opt out provision just be for some length of time the first couple of years or something like that, or would it always be the case that customers who didn't like this rate would be able to opt out and go back to a non-critical peak pricing rate?

MR. HUNGERFORD: I don't know that I can speak to the mind of the Public Utilities commissioners on that issue, but I can express a personal perspective on that. That is that the opt out rate and the opt out rate design as it currently been conceived in the order asking utilities to propose such rates.

The costs of providing power on peak during critical periods are already built into the forecasted revenue requirement and the forecast procurement costs. Thus, the insurance, if you will, the risk for those critical periods is already included in the current rate.

The idea of the critical peak rate is that if you are shifting some of that risk and the cost of that risk onto customers and the customers will have the choice either to use power or not use power and avoid the cost on the critical peak rate, they will receive a rate discount for going on to the critical peak rate.

In a hot year, if they can't reduce load, they are going to produce more. In a cool year, they are going to pay less. So, it seems as if the choice to opt out would be based more on an individual customer's operation.

If they want to average out that risk and the cost of providing for that risk over a long period of time rather than accept it on a yearly basis or on a monthly basis, then they might want to go to that average rate in the same way that its small customers tend to like average billing.

COMMISSIONER PFANNENSTIEL: Large customers now, for the most part I understand, are on time varying rates currently.

MR. HUNGERFORD: They are. They are on time-of-use rates.

COMMISSIONER PFANNENSTIEL: Right, and I am sure that some of those customers don't like having higher peak prices on their current rate. Why wouldn't they just argue, well gee, I would rather have a flat rate then. I just want to go to a flat rate. Well, the point is that the rate they are on was adopted as being an appropriate rate for a number of rate design considerations, you know, revenue, cost, and all of that currently.

I am not suggesting that the critical peak pricing rates might maybe next year be the only rate available, but I am suggesting that if it is an appropriately designed rate, then ultimately it should be the rate, or shouldn't it be the rate for that whole customer class rather than remaining some kind of experiment that customers can elect to stay on or off?

MR. HUNGERFORD: That is certainly a possibility. I want to point out two things that your comments raised. One of them is that, yes, large customers are all on time-of-use rates.

Everybody with over 200 K that has an interval meter, and there are a few that have come into the system since the AB29 "x" meters were installed that don't have meters, but the majority of them are.

As a customer class, they have responded to the time-of-use rates and moved operations to shift load off peak on a regular basis. We actually have a report, an internal report in the Commission that shows the results of the study of that customer group as a result of the meter installation.

So, business that is already or a manufacturing operation that are an intensive energy user who have already moved their load off peak because of the time-of-use rates or a substantial portion of their load off peak due to these current rates, don't have a whole lot more to gain from changing rates, especially again, when the certainty of how long that rate is going to be there is going to be is there still.

PRESIDING MEMBER GEESMAN: Is that report you mentioned, a report that we have made publicly available?

MR. HUNGERFORD: Yes. Do you want me to

get you a copy of that?

PRESIDING MEMBER GEESMAN: (Indiscernible), yes, that would be quite helpful. Can you summarize the contribution then that has been made from the AB29X expenditure in interval meters, what proportion of load has shifted, did it justify the general funds expenditure?

MR. HUNGERFORD: Yes.

PRESIDING MEMBER GEESMAN: How many times over?

MR. HUNGERFORD: I would have to go restudy that report that I haven't read in four months.

PRESIDING MEMBER GEESMAN: I would certainly like to see it. As you recall, the 2004 IEPR update attached quite a bit of significance to the tax payer's expenditure for those interval meters in 2001, and probably compared to my colleagues, I have a greater tolerance for program experimentation and program design failure, but I think when the general funds spend the magnitude of money that was spent for those interval meters, we rightly do have pretty high expectations of what flows from them.

Why don't we go to public comment on

demand response. Anyone in the audience care to address this topic.

MR. SCHOONYAN: Gary Schoonyan, Southern California Edison Company. Just an observation here, and I think the discussion that took place is a very good one, the attention between a voluntary program and mandatory expectations, and how they all interrelate. The observation is this, and we made a presentation, I think, to Commissioner Rosenfeld and Pfannenstiel on the AMI proposal that we have at the Commission.

It is a different sort of an AMI architecture, but one of the things that we were looking and we thought would be a very good benefit of this is basically to implement a program that we considered 25 years ago called Deman Subscription Service.

At that point in time, there wasn't the hardware necessary to really support it. In essence, what it does is provide customers the ability to select a maximum demand that they will meet during critical times and then be able to voluntarily select which pieces of equipment or which appliances will be shut down to meet that demand when a signal goes out. In essence, for a lower rate, they would say 5 KWs, the maximum demand, and they would set various appliances or things within their home to basically accommodate that when the signal is sent out.

This is one of the benefits we are looking at with the AMI infrastructure and architecture that we have proposed at the Utilities Commission. Needless to say, that isn't going to help in the next two or three years since the implementation of this program won't be until later this decade, but I did want to bring that up as an observation of a way of handling something in a mandatory basis, but also with some voluntary selection of how individual customers can easily meet that. Thank you.

PRESIDING MEMBER GEESMAN: Thank you.

MS. LINDH: I wasn't going to, but I think I will make a couple of comments. My name is Karen Lindh, and I am here today on behalf of the California Manufacturers and Technology Association, one of those group of large customers that we have been talking about.

CMTA has been involved in the working group due process and has made I can't count how many pages of testimony and comments we've filed on this. One of the things that I think our customers, who are primarily manufacturers, primarily 24/7 kind of operations, would most likely benefit from a CPP tariff.

In spite of that, CMTA customers still believe that it should be a voluntary tariff and our definitely opposed to the notion of a mandatory default tariff. Until a whole lot of the design issues on these rates have been worked out in a more satisfactory manner, and that there is a much higher degree of predictability in terms of what these rates are going to do to our actual bills.

Part of the whole problem here is that sometimes we talk about price responsive demand, and sometimes we talk about cutting peak load demand. There is a terrible disconnect here between what it is that we are really trying to achieve. Do we want more granular prices so that customers have the ability to react to real time prices, or what we really want is for customers to shut down their operations on 100 peak hours so that all residential customers in the Central Valley can run their air conditioners with impunity.

There is some equity concern among industrial customers about what the ultimate end gain is here. We are still working to try and make sure that the rate that is developed is reasonable and fair and predictable, but there is that underlying concern that we need to be aware of as public policy makers that just mandating a rate will actually be considered highly punitive until some of these other issues are worked out.

PRESIDING MEMBER GEESMAN: How do your members feel or respond to the notion of a greater granularity in pricing?

MS. LINDH: I think from our perspective to the extent that what you are really trying to do is flow through real time prices, I think that is considered to be a more acceptable approach than the CPP which is basically a repackaging of the existing cost structure into one extra peak period.

It is a different kind of a construct. Frankly, we are not ready for real time because there is no real time price signal --

PRESIDING MEMBER GEESMAN: How are you going to get real time prices --

MS. LINDH: That's right. All you have

now is export price, and we are aware of that. We still think that CPP probably is not the be all and end all in rate design, and we shouldn't get so frozen on that, that we really are kind of losing track of what we are really trying to do is provide people, including residential, with the granularity of prices so that they can make responses over the long haul.

PRESIDING MEMBER GEESMAN: Thank you. Other comments from anyone in the audience, anybody on the phones care to address this question?

(No response.)

PRESIDING MEMBER GEESMAN: Dave, I think you are done.

MR. HUNGERFORD: Thank you.

PRESIDING MEMBER GEESMAN: Nice job. We will break for lunch and come back at 1:00.

(Whereupon, at 11:44 p.m., the workshop was adjourned, to reconvene at 1:00 p.m., this same day.)

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AFTERNOON SESSION

1:03 p.m.

PRESIDING MEMBER GEESMAN: We will pick up where we left off. The next topic up on our agenda is renewable resources, Pam Doughman.

MS. DOUGHMAN: Hello, I'm Pam Doughman, and I am staff in the Renewable Energy Program. I'll be talking about some of the key issues related to implementing the RPS that we highlighted in the loading order paper, and also we have a list of questions here that we would like people attending today to address in the discussion period.

Regarding the status of reaching 20 percent by 2010, the 2004 procurement of renewables statewide is about 7,000 GWhs per year behind schedule. According to our estimates, which are in appendix A of the loading order paper, we would expect the state to have procured about 34,000 GWhs in 2004, and we were a little bit short of that. Actually, quite a bit short.

Some of the issues that may be impeding additional progress are listed here. The first six come from this report, which we have put on the desk in the back. This is a consultant report, preliminary stakeholder evaluation of the

California Renewables Portfolio Standard, so feel free to pick up a copy.

I've organized the issues roughly under two categories. The first is generally implementation issues associated with the rules and procedures of the RPS, and then the second category are focused on transmission and system operation issues related to renewable energy.

Essentially, I prepared this presentation to help focus the discussion, so I am just going to go through and highlight key points, so that we can go ahead and jump in to the discussion.

What I am going to do is go through each of the eight key issues, I'm going to highlight the goal or the statute requirements, and then some problems or issues that have been encountered, any updates since the publication of the loading order report, and then options to consider for addressing the issues.

The first issue is the development of rules for electric service providers and community choice aggregators with regard to RPS implementation. The statute requires the CPUC to determine RPS rules for ESP's and CCA's subject to the same terms and conditions as investor-owned utilities. However, there are differences between ESP's, CCA's, and IOU's. At the CPUC, they have been addressing these various issues, and as of June 29, there was a proposed decision released that would require full compliance with the IOU RPS rules only if the ESP or CCA is seeking supplemental energy payments.

Also, the proposed decision would allow a procurement agent to procure RPS energy for ESP's and community choice aggregators. These were two of the options that we had included in the loading order paper.

Moving on to the second issue --

PRESIDING MEMBER GEESMAN: Pam, let's go back to the first issue. If I heard you correctly, you said that we should have been at about 34,000 GWhs in 2004?

MS. DOUGHMAN: Yes.

PRESIDING MEMBER GEESMAN: We are 7,000 short of that?

MS. DOUGHMAN: Yes, statewide.

PRESIDING MEMBER GEESMAN: That is a shortfall of more than 20 percent. Then you went on to ESP's and CCA's. ESP's make up about 13 percent of the load in California now I think, is that roughly accurate?

MS. DOUGHMAN: Yes.

PRESIDING MEMBER GEESMAN: We don't have any CCA's yet. Do you think the primary -- because I know that each of the IOU's feel that they are on target for the 2010 goal, where is the deficiency come from? Is it exclusively from ESP's or --

MS. DOUGHMAN: This table might help to answer. This is in the background material towards the end of the presentation. It breaks down the various retail sellers of electricity. I am sorry for the small font size there. If you look at the category that we've labeled direct access and the rest of the state, you will see between where we think they should which is about 9,500 GWhs per year -- I'm sorry, 11,500 for 2004. For 2004, we show them only at about 4,600. That is really where the shortfall seems to be.

PRESIDING MEMBER GEESMAN: You don't include muni's at all on this chart?

MS. DOUGHMAN: Muni's, that is everybody except the IOU's in that.

PRESIDING MEMBER GEESMAN: Muni's are

imbedded there?

MS. DOUGHMAN: Yes.

PRESIDING MEMBER GEESMAN: You don't have an ability to distinguish between muni's and ESP's?

MS. DOUGHMAN: We don't have very good data on that. What we do have in the loading order paper is a summary of information that the muni's have given us. It is on page 78, it is table 12. I don't have a slide for this, but this shows in percentage terms where the muni's are in terms of their renewables procurement and the plan, but we don't have this broken out in terms of energy. So, what we do is we have information on statewide generation, and we have information from the IOU's, and so the middle box there, the direct access and rest of state, is the difference.

PRESIDING MEMBER GEESMAN: Okay.

MS. DOUGHMAN: The second key issue has to do with deliverability rules related to the RPS. We have an update here. Under previous RPS rules, previous to July 21, the renewable facilities are suppliers were required to deliver their electricity and associated renewable energy certificates to the California Independent System Operator Market Hub or substation of the IOU specified.

There were some concerns that this could pose a problem in reaching the RPS goal. As of July 21, and we expect the decision to be posted shortly. We see that the decision requires the 2005 IOU request for offers for the RPS to allow delivery outside of the IOU service area, but within the California Independent System Operator area.

This could also be construed to allow IOU's to accept delivery anywhere in California. We understand that the July 21 decision will require RPS contracts to specify that if there is a market redesign put forward by the California ISO, if that market redesign is adopted, that the IOU would take delivery of RPS energy at the busbar.

Given that these things have been accepted or our understanding is that they were accepted in the CPUC decision, promulgated in the CPUC decision. Another option to consider is whether to allow renewable facilities or suppliers to offer shaped and firmed products in their RPS request for offers.

An important thing to keep in mind is that there is pending legislation, SB107 that would revise RPS deliverability requirements for in-state and out-of-state generators.

PRESIDING MEMBER GEESMAN: On this shaped product, it is my understanding that at least one of the contracts entered into as a result of the interim procurement was for such a shaped product and that counted for that utilities RPS goals, is that a rough approximation of the fact?

MS. DOUGHMAN: Yes, that is my understanding. I think we are hoping for the clarification perhaps on the allowability of shaped and firmed products.

PRESIDING MEMBER GEESMAN: Is it clear that they are not presently allowed, or you are just seeking to make it clear that they are going to be allowed going forward?

MS. DOUGHMAN: My understanding is that it is not clear whether they are not allowed.

PRESIDING MEMBER GEESMAN: Okay.

MS. DOUGHMAN: The third point is the need to sign contracts or sufficient number contracts that will end up producing an adequate amount of energy to meet 20 percent by 2010. The problem identified here in this report, this consultant's report prepared by Ryan Wiser, is that contracts may fail to produce adequate energy for the RPS.

For example, a large number of Nevada RPS contracts have experienced construction delays or cancellation.

PRESIDING MEMBER GEESMAN: Now back when we were doing standard offers to qualifying facilities, it is my understanding from the staff that as many as 30 percent of those standard offer contracts never produced delivery of energy?

MS. DOUGHMAN: That is my understanding as well.

PRESIDING MEMBER GEESMAN: Those were pretty credit worthy contracts, so, would it be reasonable to assume a certain failure rate among these RPS contracts?

MS. DOUGHMAN: That is beyond discussion that was in the paper, but I believe that would be reasonable.

PRESIDING MEMBER GEESMAN: At some point we ought to determine whether reasonable failure assumption should be. I am not going to ask that now, but certainly if any of the IOU's have any insight into that, it would be appreciated.

MS. DOUGHMAN: I think Marwan wants to add something.

MR. MASRI: It is greener now. Just looking back on that point, Commissioner Geesman, the QF contracts had about two-thirds success rate. So, that is just relevant here in a way, there were about 15,000 MWs signed and about 10,000 came on line.

PRESIDING MEMBER GEESMAN: That is a project that signed a contract, that didn't get it its permits, or ran into construction difficulties, or thought that there was a --

MR. MASRI: Had $5.00 a KW deposit. It is not exactly the same, but there is some parallel there.

PRESIDING MEMBER GEESMAN: Okay.

MS. DOUGHMAN: There was a decision in the CPUC, July 21 decision, we believe that --

PRESIDING MEMBER GEESMAN: Let me back up. If as many as a third of these contracts, assuming the QF experience is any way indicative, as many as a third of these contracts fail or fail to produce energy, the way the law reads, that is a risk that the utility bears, is it not?

MS. DOUGHMAN: Yes.

PRESIDING MEMBER GEESMAN: The utility has got a compliance target based on delivered energy, so if the utility signs a contract with company "x" and company "x" fails to produce, then the utility is potentially out of compliance?

MS. DOUGHMAN: Yes, and some clarification on this point was included in the July 21 decision, which directed that delivered energy or I should say clarified that the delivered energy rather than contracted energy should be the metric use for RPS compliance and directed that flexible compliance should be for interim years only and not the end date.

PRESIDING MEMBER GEESMAN: Flexible compliance is the -- was it a 30 percent band on the annual performance target?

MS. DOUGHMAN: 25 percent.

PRESIDING MEMBER GEESMAN: 25 percent.

MS. DOUGHMAN: They have a three-year window, perhaps Heather's going to clarify.

MS. RAITT: This is Heather Raitt, the California Energy Commission. They have to get at least 75 percent annually, but if they don't meet the 75 percent, they have to apply for a -- I can't remember the exact term, but they basically have to apply with the CPUC for an deferral for that amount. Then they have to be able to make that up.

PRESIDING MEMBER GEESMAN: The end year is a hard and fast target?

MS. RAITT: That is my understanding from the most recent CPUC decision.

PRESIDING MEMBER GEESMAN: What are the consequences of non-compliance?

MS. RAITT: There is a charge of 5 cent per KWh after 25 million per year per utility is the penalty fee.

PRESIDING MEMBER GEESMAN: Thank you.

MS. DOUGHMAN: In addition to the clarification and the recent CPUC decision, staff suggests that another option to consider would be to develop additional incentives or penalties to insure utilities reach 20 percent by 2010 renewable.

PRESIDING MEMBER GEESMAN: What do you mean by that? What is an additional incentive? You inserted a word "or penalties", what do you have in mind?

MS. DOUGHMAN: We didn't really develop the concept further, but perhaps clarifying that the existing penalties that Heather suggested will be applied and how they will be applied.

PRESIDING MEMBER GEESMAN: That is for the utilities that can't read? Is there anything more to this than we ought to be concerned, we are 20 percent behind our target today, although that may not be attributal to the IOU's, but that we've got a history of contract failure and we are coming up close to our deadlines?

MS. DOUGHMAN: For example, we could start to measure contract failure rates. If something gets above a certain percentage, perhaps we would apply some additional penalty.

PRESIDING MEMBER GEESMAN: Is the contract failure the fault of the utilities signing the contract? It seems to me we want the utilities to develop a fairly timely procurement cycle and enter into an appropriate number of contracts, but failure on the part of a contracting party isn't necessarily the fault of the other contracting party.

MS. DOUGHMAN: Another option, perhaps

would be to do the reverse, to provide some reward for going say 130 percent of the APT.

PRESIDING MEMBER GEESMAN: Edison has not liked it when we have talked about raising target levels for them, I'm not certain anybody else would like that either, but I think I have a better understanding of what you are suggesting.

MS. DOUGHMAN: The fourth issue is related to the complexity and the slow process that we have experienced so far in implementing the RPS. For example, the 2003 or 2004 RPS RFO's were slow to produce signed contracts.

On Edison's 2003 RFO was more than 14 months late, PG & E's 2004 RFO was more than 4 months low, and San Diego Gas and Electric has not yet announced results from its 2004 RFO, which is more than three months behind schedule.

Stakeholders participating in this preliminary stakeholder review of implementing RPS identified a number of causes of delay including the starting points for the contacts, terms, and conditions, and the stop and start of the federal production tax credit, and wind turbine shortages.

One source of the complexity in the RPS is that the CPUC requires each utility to develop a transmission rank and cost report before issuing a request for offers.

No other state uses a process requiring regulatory approval that must be formally applied in RPS fit evaluation.

PRESIDING MEMBER GEESMAN: Now SMUD told us at an earlier workshop that their renewable solicitation or their most recent renewable solicitation had taken over a year to complete, and I don't think we've seen any results yet from Los Angeles' solicitation from last summer.

Do you have some broader context other than just my recollection of SMUD and LA that we could use to evaluate how reasonable the experience of the IOU's has been.

MS. DOUGHMAN: I think there was something in this report prepared by Ryan Wiser. I think he essentially would agree with you that RPS contracts tend to take a longer period of time than other generation contracts, but that is not to say that we shouldn't try to speed up the process.

PRESIDING MEMBER GEESMAN: Yeah, we've spoken before about whether there weren't more terms that could be standardized, and I think we will need to go just observe the experience of the 2005 procurement cycle to determine if that is a good idea or not.

MS. DOUGHMAN: In fact, that was one option to consider to address the problem that staff included in the report.

A second option is to possibly impose regulatory deadlines for utility procurement or expedite RPS eligible contracts in the CPUC long-term procurement proceeding, and then for 2006 and future RPS RFO's, the CPUC should develop a new approach to transmission cost ranking drawing on the California Independent System Operator's expertise.

PRESIDING MEMBER GEESMAN: Okay, now what do you mean by your second bullet "Expedite RPS eligible contracts."?

MS. DOUGHMAN: This is really meant to be sort of a seed for further thoughts, thinking what could be done to possibly review contracts that would be RPS eligible perhaps before other contracts.

PRESIDING MEMBER GEESMAN: Review at the PUC?

MS. DOUGHMAN: Yes.

PRESIDING MEMBER GEESMAN: Okay, so that would be expediting after a contract was submitted to the CPUC?

MS. DOUGHMAN: Yes.

PRESIDING MEMBER GEESMAN: Okay. On the third bullet, "Drawing on the ISO's expertise --", what do you mean by that?

MS. DOUGHMAN: Essentially, there has been some debate regarding the transmission cost ranking report as to what extent or how closely it matches the California Independent System Operators actual process or actual cost that it will assign for a transmission associated with RPS projects.

PRESIDING MEMBER GEESMAN: This is the so called system impact study?

MS. DOUGHMAN: Yes, and so this option would simply be to involve the California ISO more closely in reviewing, revising, developing a new approach that perhaps more closely matches the actual cost that would be allocated to the RPS project, and yet is somehow more streamlined or simple to apply.

PRESIDING MEMBER GEESMAN: Okay.

MS. DOUGHMAN: The fifth issue has to

dow with the market price reference supplemental energy payment structure of the RPS. This structure adds to the complexity of the RPS program and creates a possible additional source of delay in reaching RPS goals.

The first bullet just summarizes the process. Essentially, that if renewable energy costs are more than in market price reference than the additional cost may be eligible from the public goods charge in the form of supplemental energy payments subject to certain cost constraints.

Administering the MPF and the supplemental energy payments requires significant oversight and adds administrative complexity to RPS implementation. One option to consider that is included in the loading order paper is that the state should consider the pros and cons of eliminating the MPR and the RPS program. Instead the cost of purchasing or contracting for renewable resources should be included in customer rates separate from the public goods charge.

PRESIDING MEMBER GEESMAN: How do you create downward pressure on renewable prices under that last bullet?

MS. DOUGHMAN: I think that the argument that was included in Ryan Wiser's report, Preliminary Stakeholder Evaluation of the California Renewable Portfolio Standard, was that the combined structure of the MPR and the set actually does not provide downward price pressure because the utilities are indifferent as to whether the bids come in at or above the MPR price because they don't pay anymore than the MPR.

If you reunite that price, you do away with the slip, sort of cost recovery mechanisms, then they would have to use the normal cost recovery mechanisms to pay for the RPS contracts.

PRESIDING MEMBER GEESMAN: Okay. Commissioner Pfannenstiel.

COMMISSIONER PFANNENSTIEL: Two questions on that bullet point. The first sentence reads consider eliminating the MPR unless the MPR and all supporting information are public. That sort of implies that if all that is public, then you wouldn't want to eliminate it. I feel that you were getting to other reasons you might want to eliminate the MPR, it wasn't just the transparency of the information?

MS. DOUGHMAN: Yes, this probably should

be divided into two options. One of the problems for the administrative complexity is the fact that the process is not very transparent, and that makes it difficult to oversee.

PRESIDING MEMBER GEESMAN: Not very?

MS. DOUGHMAN: Not --

PRESIDING MEMBER GEESMAN: Which part do you find remotely transparent?

MS. DOUGHMAN: I stand correct, it is not transparent. One option would be what is written here, the other option would be what I actually said in my words --

COMMISSIONER PFANNENSTIEL: That is a just a different problem. Then the question of the cost of the RPS going into customer rates. Do we have any idea, has anybody done an analysis of what that might look like and what that impact might be? I mean, I am not sure how we go about having that discussion until we have some estimate of the impact.

PRESIDING MEMBER GEESMAN: Commissioner, you are on the renewables committee, and I know for a fact you've not seen one single bid yet.

COMMISSIONER PFANNENSTIEL: This is correct.

PRESIDING MEMBER GEESMAN: We don't know if we are talking about 3 cents a KWh or 8 cents a KWh for any of these proposed RPS contracts. Is the Committee responsible for recommending the award of SEP's, and I'm not certain that we've gotten a single application for an SEP either, but as that Committee, I would think that we should probably know that in order to properly ruminate on this type of recommendation. Not one single aspect of this process is transparent, including to the ostensible decision maker for the award of fairly large amounts of public funds.

MS. JONES: Pam, is there an additional issue with the MPR in terms of the complexity of actually setting up the MPR calculating it. The law called for a MPR, but didn't specify the complexity that we are seeing the PUC move towards in establishing that MPR. Would a simplified method be an improvement?

MS. DOUGHMAN: Yes. Okay, moving on to the sixth point. Transmission needs for renewable energy. To meet its ambitious renewable energy goals, the state needs new or upgraded transmission to access renewable resources.

One key issue for renewable energy

transmission is expanding transmission in a resource area in the absence of firm developer commitment to build facilities there. The Energy Commission and the CPUC support Edison's proposed or I should say support the proposal that Edison put forward on the renewable trunk line concept that would have reduced Edison's regulatory risk of building transmission to meet projected rather than actual renewable energy development.

However, on July 1, the Federal Energy Regulatory Commission disapproved Edison's petition, and parties have 30 days from July 1 to file for a rehearing.

Other options beyond the renewable trunk line concept are listed here. One would be for the CPUC, the Energy Commission, and the California ISO to coordinate their efforts at the FERC in support of clustered development of renewable facilities.

A second option when valuing potential transmission projects, California ISO's should view the aggregate potential of renewable energy for projects near the transmission line instead of only current individual projects prompting a need for the upgrade.

A third option, the state and stakeholders should encourage the FERC to allow the California ISO to tie permitting and construction approval of transmission projects to RPS generation.

For further information, please see upgrading California's electric transmission system issues and actions for 2005 and beyond, the staff report that is scheduled for a workshop on July 28 coming up soon.

PRESIDING MEMBER GEESMAN: Without wanting preempt that discussion, I think it is probably more appropriately held in that transmission workshop, it would seem to me that the common theme in each of the third bullets recommendations would be that the central nature of the ISO in cutting through this problem. I also don't want to pre-judge that the potential outcome of any petitions for rehearing the FERC July 1 decision, but I don't think any of us should pretend that it doesn't represent a pretty significant setback to the state's efforts here.

MS. DOUGHMAN: Moving on to the seventh of the eight issues, integrating wind energy into California's electricity system. Now this is a topic that was researched by CEERTS and discussed earlier in this 2005 IEPR round of workshops. I'm just recapping here to best fit California's electricity system needs, RPS suppliers should strive to delivery energy on summer afternoons and avoid delivering energy at night when energy demand is low.

Many California wind sites produce most energy in the spring and early summer with energy lowest around noon. Ryan Wiser I think on May 9 presented some of his work showing the wind generation profiles in California as well as other western states.

That leads to the third bullet, many wind sites also in the west peak in winter months, while others have smaller seasonal changes or patterns like California wind. The staff report, the loading order report suggests some research needs to anticipate and adjust to the impacts of RPS energy on system operations and dependable peak capacity, and also to identify the extent to which shaped products, energy storage, or hybridization as well as unbundled REC's can improve the fit of RPS energy to the California electricity system.

The last point has to do with the need to take further action to reduce bird deaths from wind turbines. This was discussed at the workshop on the 2005 Electricity Environmental Performance Report. To recap here, just beyond removing existing problem turbines, the Energy Commission staff believes further efforts are needed to reduce deaths of avian species protected by domestic and international law.

Some options to consider include establishing a standing statewide working group to develop regulatory procedures, guidelines for wind projects to comply with state and federal law including CEQA.

Another option would be to develop private/public partnerships to sponsor environmental studies of known wind resource areas to determine how best to protect birds.

A third is to compile an archive on important wildlife migratory corridors to be used in permitting wind facilities.

For further information, please see the 2005 Electricity Environmental Performance Report.

PRESIDING MEMBER GEESMAN: Were you here for the workshop that we held on avian mortality?

MS. DOUGHMAN: Yes.

PRESIDING MEMBER GEESMAN: I guess the reaction I had to it focusing on your first bullet and also centering on the Altamont experience which is where most of our data, almost all of our data come from, what I took away from that discussion was that more than talking simply about removing existing problem turbines, that recommendations of the biological staff and consultants was to replace existing turbines with newer larger turbines. If I recall correctly, the higher blade height alone resulted or projected to result in the Altamont of about 81 percent reduction in bird kill. I think we need to focus, and I believe in terms of the dialogue that we had with the fellow from Alameda County, he certainly was receptive to the notion that we want to see new investment in those wind fields, modern technology brought to those sites with what we think to be a reasonable expectation that will be a result in significant reduction in avian mortality.

MS. DOUGHMAN: Absolutely, and I meant this to indicate beyond the recommendations in the 2004 IEPR update, which included repowering existing wind sites with new larger turbines with the blades lowest sweeping point raised about 29 meters from the ground. There are a number of other -- that alone would do quite a bit to reduce bird deaths, reduce avian deaths I should say.

Although, the extent to which the bird and bat flight patterns from the Altamont area are the same or different in other areas is still in need of further research.

PRESIDING MEMBER GEESMAN: That's right, and I think that was a point made at that workshop as well.

MS. DOUGHMAN: Now we have eight questions for stakeholders related to the RPS. These were included in the loading order paper as well. The first is that the RPS establishes a statewide goal that 20 percent of California's retails sales would be served with renewable energy delivers by 2010.

The 2004 Energy Report Update suggested 33 percent by 2020. To date, however, the program appears to be following behind schedule to focus on the statewide goal, and the question is what actions are needed to correct this trend.

We would like stakeholders to priortize

the key risks to meeting these targets and recommend corrective actions.

The second question, what actions should be taken to foster timely and necessary transmission to support renewable development. What milestones and target dates can be identified to measure success?

The third point, the June 29th CPC draft decision, was that a framework for EPS/CCA RPS implementation? What actions are needed to insure that ESPs/CCA's meet their RPS obligations?

Number four. What could be done to develop a RPS framework with a faster contracting process and transparency that would most assist the IOU's in meeting their RPS goals.

The consultant's report that I have been referring to in my presentation recommends considering eliminating steps in the MPR as a long term policy issue to insure clear price signals to the utilities and renewable generators and to simplify the program requirements and implementation and should the Energy Commission support this proposal.

Number six, if supplemental energy payments and the market price reference were eliminated, how should the state contain RPS program costs. If supplemental energy payments are eliminated, how should the funding collected for sets otherwise be used to facilitate accomplishing the state's renewable energy goals.

Number seven, does the Energy Commission's process to certify renewable facilities adequately meet the RPS program needs? If changes are needed, please identify the problems and recommend remedies.

Lastly, how could other western states and programs be encouraged to participate in the Western Renewable Energy Generation Information System?

Then we also have some questions related to renewable distributed generation. There are seven questions.

The first is how should a declining rebate be structured to maximize distributed renewable capacity and energy while minimizing funding disruptions.

The second question, to what extent should installation of energy efficiency measures be required prior to qualifying for renewable distributed generation incentive? What criteria should be used?

Number three, how soon should performance-based incentives be more broadly implemented for renewable distributed generation systems?

Number four, what steps would be needed for the emerging renewables program to charge and application fee? Should it be similar to the fee implemented by the CPUC for the Self-Generation Incentive Program.

Number five, should the equipment and labor warranty required to qualify for renewable distributed generation incentive be increased to ten years?

Number six, how can incentives for distributed generation photovoltaic systems be changed to bring system costs in California down to levels similar to those in Germany and Japan?

Number seven, should the various solar incentive programs in California, that is municipal utility programs, self generation incentive program, and emerging renewables program be consolidated to implement the unified strategy to create a self-sustaining solar PV markets, and if so how?

Then I have a list of link and documents that you can refer to for further information. That is all I had.

PRESIDING MEMBER GEESMAN: Okay, why don't we go to public comment. Anybody in the audience care to address any of these issues?

MR. FREEHLING: Good afternoon, I'm Robert Freehling from Local Power. Local Power is responsible for helping to create California's Community Choice Law which is one of the issues that was raised here today.

Community Choice actually addresses a number of the questions that were raised regarding this last presentation here. Many of the questions that were answered in the negative today, Community Choice attempts to provide an answer in the affirmative.

For example, I will go through the list. You asked if there are pressures in place to reduce the cost of renewable energy facilities, and the answer with Community Choice is a resounding yes, and that is because Community Choice sets up a contract with an energy service provider, electric service provider, and the cost of that renewable is born directly through the electric system. It is not passed through an automatic charge that raises everyone's rates.

The pressure to reduce the cost of renewables is built into the contract structure. If the cost of renewables exceeds the amount of where it starts to impact the rates, then people are going to have to compete with the standard service and see whether they really want to go to an electric service provider. So, there is a built in competition structure between the existing rates and an electric service provider.

This is something that does not exist as long as of course that you have only a utility monopoly providing power.

Second question was regarding transparency. Renewable facilities are expected to be and are planned local powers model to be financed by public bonds from Community Choice aggregators to the extent that is feasible to do so.

These bonds would be publicly issued. The energy plans for cities are required as public documents to state how much renewables are planned for the cities. San Francisco, actually, has by ordinance specified the amount of MWs of photovoltaics and wind and through the implementation plan, which is also a public process, specifies how renewables are to be integrated and what renewable targets are going to be met.

Finally, there would be a bidding process at the end where a contract would be brought up and the terms would also be a matter of public disclosure at a certain point. So, clearly more transparency than exists in the current process.

PRESIDING MEMBER GEESMAN: Do you know if those bonds would be eligible for tax exempt status?

MR. FREEHLING: That depends on the ownership status of the renewable facilities. If the ownership is maintained directly by the CCA, which is in fact the city government, or in the case of cooperation between cities could be a joint powers authority, then the ownership would be by a public agency, and so of course those would be tax exempt bond, so you would have very low interest rates, considerably lower than utilities, so this is yet another important example of how to reduce the cost of renewables.

Another example of questions of timing on the RPS was another question that was raised here. Timing is critical for an energy service provider's contract because of course costs are born by most renewables up front. So, the faster an ESP gets that renewable on line, the more quickly they can sell electricity from that system.

If they delay a year, two years, three years, that is actually costing. Ultimately it would impact the ratepayers, but they can't just simply pass that through the ratepayers freely. They are under a contract to supply power at certain prices. So, there is a tremendous pressure on the ESP to get those renewable deployed on a schedule, and if they go two years, three years, four years, they wait that time, you are going to have a huge impact on the annual budget.

Another question that was raised was bringing in actions that would meet the goal. The question of stakeholders, do we need new stakeholders. Cities would be precisely the new stakeholder that would provide a motive and a direct contract that would say you need to bring in so much renewables into our energy supply, so by bringing a new stakeholder into the process, you in a sense have to rebalance the whole equation. You have to look at it from scratch, it is not just business as usual. In fact, you get to write the book again from scratch each time a community choice aggregator comes on line with an electric service provider comes up with their own implementation plan.

These implementation plans that have to be approved, so that in turn is a review process that would be a public process that would look into renewable portfolio standards, the economic viability, the impacts on the grid and so forth. That is not just something that the city signs by itself with the electric service provider without public oversight is my point.

Another question that was raised was what actions are needed for CCA's. Certainly the Energy Commission can facilitate these goals by any means that would free up or facilitate development of renewable energy in California. It is the plan of San Francisco, and certainly it would have to be part of the plan of any Community Choice aggregator coming into existence at this point to have to actually build new renewable portfolio, new renewable facilities.

Renewable facilities in California, it is my understanding are mostly, the electricity is mostly claimed from the, and so San Francisco's plan is specifically to put 360 MWs of not just renewables but also energy efficiency on line within the first few years of its coming into existence.

I don't know if you had any questions, but those are my main points.

PRESIDING MEMBER GEESMAN: Have you had a chance to take a look at the CPUC's June 29th draft decision?

MR. FREEHLING: No, I haven't, was there a particular pointed you wanted to --

PRESIDING MEMBER GEESMAN: I just wondered your reaction to that draft decision. Are you familiar with the proposal I think mentioned in the staff report for a potential procurement agent for ESP's and CCA's?

MR. FREEHLING: There are different possible models for how renewables could be built under Community Choice. This is one of the advantages, actually Community Choice is, that there are so many directions that things can be developed out of. You can have private independent development of this by the electric service provider, or they can contract out to a third party who could develop that.

The cities themselves can also develop an own these facilities, so depending on what is optimal from an economic point of view. Of course these depend on policies to some extent that are out of reach of cities to decide at this point.

For example, the question of whether the tax credit for wind power is going to be reinstated by the federal government or not is huge.

On the other hand, the other balancing side of the equation is that if cities own these renewable facilities, they are not going to demand the type of profit margins that a private owner is going to require, so if there are no tax credits in the works, the cities, the CCA's may be in the best position to finance, especially things like wind because they don't require the profit return that a private investor is going to require. They are going to have a lower interest rate.

So, the answers to most of your

questions in the last presentation for CCA's are, yes, it is designed to answer most of these questions in the affirmative. Whether it succeeds in doing that is a matter of whether the market can meet those demands, and of course that is what we are making the effort to develop. Thank you.

PRESIDING MEMBER GEESMAN: Thank you very much. Other members of the audience that care to address this topic? Les?

MR. GULIASI: Good afternoon, Les Guliasi for Pacific Gas and Electric Company. I don't intend to go through all eight questions, but I think my remarks will touch on several of them.

Just to start with confirming the statement you made earlier, Commissioner Geesman, indeed PG & E intends to meet the RPS goal by the year 2010. When we talk about acquiring renewable resources, we want to make sure that whatever target is set or whatever goal is set by the state that the power that we end up purchasing is reasonably priced, and that we have the ability to integrate that power into our system.

We also want to insure that the pace of development encourages the development of the industry as a whole, as well as the various types of renewables within the renewable industry per say.

One of the goals of the program is to insure that new resources are developed, and that is to put new steel in the ground, to use that cliche. That new power projects are actually developed.

There are very promising technologies and other technologies that really still need a lot of development to be fostered. We want to make sure that whatever technologies are developed, we foster the emergence of new technologies, but we also want to avoid a situation where we have a seller's market, that is people selling whatever resources are currently available.

The Energy Commission has done a lot of laudable work to identify the potential for renewable resources, not only in California, but throughout the west. The experience that we've had through our solicitations bears out the Energy Commission's research. That is most of the available resources are within Southern California, mainly within Southern California

Edison's service territory. There is a very limited amount of potential within the PG & E service territory, so we are talking about imports.

Wind as we know is the most abundant resource, but for PG & E it does not fit very well with our system. We heard a little bit about some of the patterns that we see with wind. It just doesn't fit very well our resource needs, at least at the moment.

PRESIDING MEMBER GEESMAN: What was your reaction last to the somewhat vague allusion to out-of-state wind and the availability of that capacity coincident with PG & E peaks?

MR. GULIASI: I think there's some promise to find ways to incorporate wind that is coincident with our peaks. We have the problems that we have just identified, that is importing that power through transmission.

There are going to be solutions or maybe as we see load patterns or grow or differ, perhaps we can find a way to incorporate wind power to meet customer needs if the load patterns change. There may be some potential there.

PRESIDING MEMBER GEESMAN: You might

also want to consider expanding your pump hydro operations.

MR. GULIASI: That is an issue. We want to encourage the Energy Commission's work, there is a lot of interesting PIER work that is going on, taking a look at what to do with the intermittency problem.

Geothermal and biomass technologies fit better with our operational needs right now. Solar may fit well, it depends on the type of solar we are talking about. Right now, costs for solar development are high, and we need to do whatever we can do to encourage those costs to come down.

PRESIDING MEMBER GEESMAN: Your company has been pretty enthusiastic about solar thermal application, though, has it not?

MR. GULIASI: I was just going to say that one application that may suit our needs well is consecrating solar, and especially combined with thermal gas fired thermal may be a good fit.

PRESIDING MEMBER GEESMAN: I'm sure you were referring to IGCC with carbon sequestration coal fired.

MR. GULIASI: Of course, a topic that I

guess you are going to take up in a couple of weeks.

PRESIDING MEMBER GEESMAN: When you speak of concentrating solar, are you thinking there in terms of something inside your service territory, or would that constitute an import as well?

MR. GULIASI: Probably an import. Again, most of that potential is outside of our service territory. There may be some areas where there may be applications, but once again, we are talking mostly about the Mojave Desert or the Imperial Valley.

One of the things that we are doing is actively encouraging repowering of existing renewable resources, both through our renewable portfolio standard solicitations, as well as through all-source solicitations. Since the RPS program went into effect, we have signed 13 contracts for 443 MWs of power. We just announced that we are going out for I think it is our fourth solicitation in early August. We are hoping to add at least another one percent of renewable power to our mix. We are currently at 13 percent, and if we continue to add at least 1 percent a year, we will meet our legislative mandate by the year 2010.

PRESIDING MEMBER GEESMAN: I think you make a good point about repowering. As you know, the June 2003 CPUC decision on RPS tried to emphasize to the IOU's the importance which the Public Utilities Commission placed on repowering existing wind contracts, and this Commission has made similar statements in the past.

I think that your company could probably be the primary contributor to improved avian mortality with more repowering contracts.

MR. GULIASI: I think we have now more than 700 MWs of wind power in our system. I think we had 700 MWs before the contract were approved last week, and I forget what the exact number was of wind, but now we are beyond 700 MWs of wind power.

PRESIDING MEMBER GEESMAN: I think there is a tremendous opportunity for you there.

MR. GULIASI: That concludes my remarks, are there any further questions?

PRESIDING MEMBER GEESMAN: Thank you.

MR. GULIASI: Thank you.

COMMISSIONER PFANNENSTIEL: Les, I can't

resist. What is your opinion about whether there is any possibility of eliminating SEPs and the MPR. Clearly that would simplify the process, have you looked at, has PG & E looked at what that might cost or how that might be done in a way to minimize rate impacts?

MR. GULIASI: No, I am not aware that we've actually studied that. We may have, but I may just be unaware of what we've done to look at that specific question. I know there is a recommendation in this report, but you know, we were unable to fully understand where that recommendation came from, what analysis underlies that recommendation, but that is something that needs to be looked at. If we have something to say on that, we can write it in our comments. Thank you.

PRESIDING MEMBER GEESMAN: Other comments by members of the audience?

MR. KELLY: Thank you, Commissioners, Steven Kelly with Independent Energy Producers. I'll try to be brief. I've actually been out of the state for a couple of weeks, and I am totally up to speed on the stats report, but I had a chance to breeze through it.

I would like an opportunity to try to respond briefly to the questions. It is kind of ironic, I don't know if this is good or bad, but I think in 2001 I stood in front of this body, and this was either during or after the debate on SB1078 and said that I didn't think any new renewable MWs were going to come on line for three to five years, and alas, I was overly optimistic. Usually my problem, but there has been some progress, but we are not at kind of the curve, and the utilities are negotiating some contracts.

PG & E just indicated that they had some contracts in place. I know that Southern California Edison did, and SCPPA has got some that are coming forward.

I kind of find it amazing, though, that SCPPA was able to bring theirs to the floor once they engaged in the process of negotiating very quickly. It kind of shows that when a utility wants to engage in the contracting process, they can get it done very quickly and bring a lot of MWs on. I think that is hopefully a good sign of a trend.

The staff have asked a couple of questions regarding kind of the impediments for and ask me to priortize the key risks, and I would briefly say that in my mind, one of the biggest impediments this Commission faces and indeed the PUC is SB1078. The way that was prescriptively drafted creates impediments to timely and effective procurement. It has always been the problem and I think until we actually tackle that issue and simplify the California RPS, we are always going to have problems and always be concerned about meeting compliance deadlines.

Texas has a five-page RPS, California's is what, up to 50 now, and there is talk about expanding it in this legislative cycle, which I would like to address in a few seconds. It is incredible. That in my view is the big problem. It is the big elephant in the room, and until we as a state decide to tackle that, we are always going to have problems I think in timely procurement.

The other observation that I have in a risk is one of the things I see when the utilities actually conduct solicitations is they kind of adopted what I call the Toyota model for procurement, it is in-time procurement.

We need one percent so we are going to

go out and we are just going to get one percent, that makes them RPS compliant. That is fine, it is very positive, but I am surprised, at least as far as I can tell, and I don't get to see a lot, that there is not an issue about maybe, gee, this is low hanging fruit out there, we ought to get more. We ought to be getting 130 percent in case 25 percent of the contracts don't come to fruition.

I don't see that happening now, and it surprises me, and I think it almost guarantees that we run the risk of being short as was alluded to in some of the staff presentations this morning because of either projects that fail to come on line for whatever reason or the selection of bad projects in the procurement process.

PRESIDING MEMBER GEESMAN: The staff said that were that to happen, that is a risk born by the utility with a penalty of five cents a KWh. Don't you think that is a meaningful penalty to the utilities?

MR. KELLY: If I had any belief that penalty was actually going to be imposed, yes, perhaps. I just don't have any confidence that penalty at that level is going to be imposed. The language in the statute is pretty vague on this, and there is a lot of discretion at the PUC about the imposition of that kind of sanctions, and they have never come out and said exactly that they are going to do that, or if they are going to do it, I think it's maybe time that they do that.

PRESIDING MEMBER GEESMAN: You ever seen any comparable penalty imposed by the CPUC?

MR. KELLY: I cannot recall any comparable penalties in this regard. I would have to think about that. I mean I am trying to think. It might have been in some of the programs where they were going to manage program funds and they got incentives to do something well. I don't know if there were sanctions in that.

I have to confess, I am not that conversant with all the issues and incentive programs that utilities face or benefit from.

I do think that the end time procurement tactic that seems to be employed today, it creates delay, but it also creates a problem of what do you do when you are short, and it is going to put the agencies in a problem if that comes to pass and some of these contracts don't come to fruition.

The other thing that impresses me as I look at the utilities in terms of impediments to achieving the goal is based on my conversations and my sense of what is going on, is I think the utilities are very understaffed in the renewable procurement programs. I just don't think they have the time to do as many procurement as it might take to reach this goal.

I've always been a little surprised about that. I know some of the people that are doing very good work in the utilities on this procurement end, but I happen to know that they are working on a lot of other major issues too. It is the same people working on similar subjects. I know because I am doing the same thing, and it is a lot of work. I just think there is an understaffing issue there, which kind of gets back to this issue about should there be a penalty or not.

In my view, I think senior management in the utilities have made a conscious decision to under fund these programs, which is going to create the conditions for not achieving the goals, and maybe a more transparent or clear position of the PUC on sanctions would be helpful to stir that up.

Question number two asks essentially takes up the issue of transmission to support renewables, and transmission and generation is a chicken and egg product. It is a key impediment in many respects to going forward, though I will note that I don't think as far as I can tell, there has been enough in-state generation bid in the utilities are post to date, that hasn't triggered the need for new transmission expansions. I am a little vague on that because I don't get to see their analyses.

Just as a general matter, I would just urge this Commission not to buy into the argument or the expectation that FERC is going to step up and overturn their 20 to 30 year policy on the cost recovery for gen ties and network system additions. They just rendered a decision on that. I was not surprised that they had taken the position they did, which essentially said these two (indiscernible) on the tatoo line look gen ties or system benefits. We are going to cover that to the rate this other one doesn't. That is very consistent with where they've been for 20 or 30 years.

So, as a policy matter, I am just not convinced that approaching FERC and asking them to overturn that policy in order to help the State of California to meet their RPS goals is a good use of our time. It is a good endeavor, but if we have everything hinging on that, again, I think we will be waiting and waiting and waiting.

PRESIDING MEMBER GEESMAN: I guess I should say, Steven, you are a better vote counter than the former chair of FERC in that regard. In his farewell interview, he gave the State of California a D+ in addressing infrastructure needs since the 2001 electricity crisis. That is a grade that I would generally concur with, but he also said that he did anticipate not having any problem getting a majority of FERC commissioners to align with him in providing the state the important tool represented by the Edison Trunk Line Proposal.

He was wrong in that. I am pleased to hear that your vote counting is as good as it is, and I am afraid that I tend to concur with you that well is dry back there. We are not likely to get much more water out of it.

MR. KELLY: Yeah. I supported the

Edison proposal, but I also even when they made the proposal in Denver, whenever it was, this requires FERC to do some major stuff. In California, we all support that, that is fine, but when you are in FERC and there are other utilities involved that may not share that view, then I was just skeptical that it would ever come to pass. I hope it does, but I just don't think we should hinge on that.

PRESIDING MEMBER GEESMAN: So, where do you go?

MR. KELLY: I think that there are transmission configurations that are easier to describe as network upgrades that can be done, Tehachapi, I know there are discussions about that, and if you link it on the far north, it looks like a network upgrade. Maybe it is worthwhile to consider broader transmission upgrades in order to get it into that network upgrade classifications so you can do cost recovery.

Maybe we can think creatively about how to handle transmission costs for the utilities to make sure that they've got cost recovery through retail rates.

PRESIDING MEMBER GEESMAN: Let me ask you there --

MR. KELLY: Defining through a definition.

PRESIDING MEMBER GEESMAN: Let's assume that you were able to achieve that, does it make any sense for -- take the Edison ratepayers as an example, for them to pay 100 percent of those Tehachapi transmission costs? It seems to me that if you are talking about retail rates, you are talking about one utility or another as opposed to all of the ISO grid users.

MR. KELLY: If the system upgrades I will call them, I am not going to call them transmission to grid facility upgrades, are designed to foster delivery to Edison. The costs are going to be no, right? So, if there are other utilities that are benefitting from the generation that is being built in that area, the transmission costs associated with delivering that energy to the grid can be captured somehow I believe in a transfer. I don't think it necessarily has to be that complicated.

PRESIDING MEMBER GEESMAN: Welcome to the world of rate making. It is always complicated.

MR. KELLY: If there is the will to get it done. All these things are a problem. If there is an interest in delaying or not getting it done, and there are a bezillion reasons why things get strung out, that is why 1078 was such a great bill, if there is a will to get it done, then it is pretty simple.

I am sensing from the utilities, and there are probably comments, and certainly from the renewable industry and the regulatory agencies, that there is a will to get this done. Now that the FERC avenue may be foreclosed, I think it is time to start looking seriously at getting it done.

We all agree that the utilities should be made whole on this. That is not the issue, so as you point out, we are in the issue of cost allocation. It can get complicated, but I think we do a lot more complicated cost allocation issues here in the State of California.

Staff have also asked the question what to do about the ESPs and the CCAs to meet their RPS obligations. I tend to think that this doesn't have to be -- this is another one of those things that gets overly complicated quickly and can be made more simpler. The proper accounting and counting for renewable generation and REGIS, that is the whole thing that REGIS is supposed to do. Should provide the means for the ESPs and the CCAs to provide a report to the PUC to verify their RPS compliance. I think they can use broker services to facilitate the purchase of renewable energies.

I also think that recs should be available to them. I think they should be available to the utilities as well, but some of them apparently do not want them or feel that the legislation prescribes them from having them, but recs would be a good means to have the ESPs become RPS compliant.

PRESIDING MEMBER GEESMAN: In-state recs, out-of-state recs?

MR KELLY: I'm talking about recs associated with certified renewable energy that has been delivered in-state.

There is some talk, and Commissioner Geesman you mentioned this talk about the procurement entity that is I think a turn has raised, it's had some discussions late last week and is talking about legislation in that regard. Let me comment on that a little bit.

I look at the procurement entity today as the same way I looked at SB1078 is that it is going to create delay and impediments. In the discussion that I had with TURN yesterday among other stakeholders. I said this is going to take two years at least to get up and running because this is a PUC regulated thing and they have to do everything just like the IOU's are supposed to do.

I said, so, what are we going to do in the interim. The answer essentially was, well, maybe we can figure out a way for the ESPs to become RPS compliant, maybe use short term recs and blah blah blah.

Why don't we just do that, and that's what the regulatory process to create a procurement entity regulated by the PUC, given the tools to get compliant. I just think right now my view and analysis of the procurement entity is that it is very complicated. It is going to prone for a lot of delay, and it is not necessary. I think we have other tools to insure that the ESPs and the CCAs are compliant and that would not be necessary.

Fourth, the staff asked the question how to quicken the contracting process. Let me talk about the issue about flexibility and standardization because this came up earlier. IEP worked the utilities a couple of years ago, two years ago, I guess on adopting the EEI contract for RPS compliance purposes. One of the issues that was on the table was that the utilities wanted a great deal of flexibility.

As a practical matter, my members also wanted flexibility because the EEI contract is a little weird structure anyway. You have to have some flexibility to adapt to changing conditions.

What we ended up with is what I view as an incredibly flexible contracting tool that can meet any situation. It appears as a result of that flexibility, there was incredible delays in negotiating final deals. It may be that we were at a point of time that we need to consider a little more standardization to expedite that process.

During the times of those negotiations, I shared my thoughts with the utilities which was that flexibility that they are asking for today cannot be an excuse for not being RPS compliant when you need to make your showing. I said I for one would not allow that or want that to be the rationale for not being compliant. It is a two-way street. I deal with my members all the time, I know that they can be a pain to negotiate with.

If you have repeated procurement, nobody is saying that they have to buy from the people who bid, have another procurement and just roll them until you get the amount that you need. If somebody is recalcitrant, don't talk to them.

PRESIDING MEMBER GEESMAN: It strikes me and to pick up a theme in this consultant report that much of the complexity in SB1078, much of the complexity in the way in which the program has been administered is driven by this MPR SEP approach. The RPS solicitations are I think intended to fit into the MPR SEP approach. Why couldn't you standardize a greater number of the terms in those solicitations, and then if someone wanted the greater flexibility, either on the utility side or the generator side, simply allow them to do a bilateral transaction without benefit of SEP. It seems to me that the existing decisions create that bilateral option for any contract under the MPR. Why don't we focus our interests in flexibility on those bilateral contracts preserve the more formal rigid SEP-driven process, and frankly I don't know that we will every award a single dollar of SEP or that we will ever need to, but reserve that for the more standardized terms and conditions.

MR. KELLY: As you pointed out, there is not very much transparency in any of the procurement processes today.

PRESIDING MEMBER GEESMAN: No, I pointed out there was none.

MR. KELLY: I agree. I see nothing, but I am a little reluctant to buy into a bi-lateral contracting approach when there is no transparency about how that gets from Point A to Point B. That concerns me.

From a developer perspective in terms of the proceedings at the PUC, the MPR SEP, I mean, I'm not even an active participant in that because all that is, is the demarkation between whether you are going to get your money from Point A or Point B. We negotiated out pretty good language the first go around on this. It is pretty clear the process, so I've never been from a procurement perspective really concerned about that. I have other reasons that I might be concerned about it, but I don't think that is the problem.

What you've got is a bunch of technical people, mostly on intervenor compensation, fighting it out down there.

PRESIDING MEMBER GEESMAN: To post-millennium BRPU.

MR. KELLY: Yeah, we are not even playing in that. Nobody has triggered the MPR to begin with. It doesn't mean anything to us yet. I am not sure that it will mean anything to us yet. There is no evidence because the procurement haven't triggered the MPR, and we are not at the end of the SEP thing that I would really get to the point and say, wait a minute, why are we draining this money so quickly.

So, that is not my -- I don't think that is the issue that is delaying contract negotiations. The language in the deal the PUC approved is pretty clear on that and allows people to off-ramp if they need SEP money and they don't get it, they can off-ramp. That is what we cared about the most. We didn't want to be tied into a contract if we didn't get all the money. If we get all of the money, we are fine.

I tend to think that is not the real impediment to the negotiations. I think delivery points are, commercial terms, things like that, credit issues, and so forth.

We are at a point where we are trying to reevaluate flexibility, and I think that there may be some reconsideration on standardization if there continues to be what I see to be a very long period to conduct these RFO's and then the negotiations that follow.

I'm just surprised at how long it takes. I know it is pretty difficult. Like I said, I think SCPPA did theirs a lot quicker, and they brought on a pretty significant amount of renewables in a relatively short period of time.

The other issue that feeds on that, though, is the issue that I mentioned earlier, I think there is a staffing problem. I just don't think the utilities have enough people to negotiate with 15 or 20 short listed bidders. That is what is really causing the impediment.

Of course, SB1078 as I indicated is as I indicated, is an impediment to this. The least cost/best fit methodology is something that I am not able to see. I don't understand really how it is being implemented. There could be problems there.

PRESIDING MEMBER GEESMAN: We've asked each of the utilities to file with us in writing how they apply those particular words. We are looking forward to going over that before we issue our report. Those will be publicly documented.

MR. KELLY: That would be great, I would like to see that. I mean you had asked the question earlier, Commissioner Geesman, if a project does not come on line in a timely manner, whose fault is it. Right now, the utilities pay a penalty, but I got this sense from your questioning that you thought that it was actually the developers problem.

I will raise the question about whether projects are being picked, not because of the feasibility of deliverability in a timely manner, but for some other criteria, maybe it would look good on the front page of an annual report.

I mean, when I see the list of projects that are selected sometimes I go, whoa, that is interesting. Is that going to come on in my lifetime.

PRESIDING MEMBER GEESMAN: I haven't

seen those lists. As I indicated, there is no transparency up here, but I will say if I was facing a 5 cent a KWh penalty, I would be reluctant to sign a contract merely because it looked good on an annual report.

MR. KELLY: One would think if you were really facing that problem. I remember a selection that occurred I think in the interim RPS that the conditions on the selection of the renewable was that one of the utilities had to seat some land under 851, the developer, so they could sell it to the other utility. That was touted as one of the big projects.

Everybody in there is just kind of going, whoa, okay. Don't hold your breath on that one, and it never came to pass. I don't know how they do the selection criteria, but if there are decisions are being made that aren't taking into feasibility of delivery, then that is not unnecessarily a toll problem which should be placed on the developers. They are just proposing projects.

I think we have already addressed the question about whether SEPs and MPRs were eliminated. I don't see that as a problem really.

I don't know if elimination or inclusion in the process is helpful. Nobody has triggered that funding source yet. I think it is simpler if the utilities would actually have a solicitation, bring their short listed bidders or their signed executed contracts to the Commission in a transparent fashion and say, we think these make sense, and we want to include in these retail rates. That is where it happens everywhere else in the world as far as I can tell, but California of course is unique.

If we could get into that mode, then I think you could eliminate the concept of the MPR and SEP, but that is part of a broader discussion about SB1078.

PRESIDING MEMBER GEESMAN: Would your members allow bids to be made public?

MR. KELLY: Yeah.

PRESIDING MEMBER GEESMAN: Transparency is not your enemy?

MR. KELLY: Transparency is not my enemy. We have had a number of discussions on this. There was some components of bids that companies are sensitive to. You know, if you get a favorable deal on a boiler, for example, or some turbine, you don't want that information released publicly, that's fine. Winning bids, we are comfortable with making winning bids public. We don't think there is value to making losing bids public because they are going to be bidding in the next RFO. The winning bids, yeah, let's make them public.

Finally, I will just conclude you had asked the question about REGIS and whether the staff had asked how other states and programs could be encouraged to participate in this. Since I am somewhat involved with REGIS, I guess I could opine that I think the thing that is going to make that interested by other states is the thing actually gets up and running.

PRESIDING MEMBER GEESMAN: Yeah, I kind of chuckled on that one as well. My answer was build it.

MR. KELLY: Yeah, we are moving pretty good on that process, and all the evidence I have as I said on the interim governing committee is it should be up and running by probably the second quarter of 2007 if there aren't any delays. We are going to go out for procurement sometime this fall. I think we are on speed there.

There are, interestingly enough, a number of other states that are participating in some of the calls, so there is some interest there. Arizona is one and based on what I am hearing, if we get the thing going, there will be -- it is kind of, if you build it, they will play. So, that is where we are hopefully.

PRESIDING MEMBER GEESMAN: You think our program ought to ultimately be focused on a west wide market, the RPS?

MR. KELLY: You know, I don't know. I think California has stepped up to the plate for renewables for a number of years. One of the benefits you get out of that is the tax base, the jobs, the things like that. I have some lingering concerns that if we did a west wide RPS, all the power would be developed in Wyoming, and we would get political whiplash on that. I don't think that is the next fight that I want to have right now.

We have a system that allows, if you can get the power across the border into California, then it counts. We need recs, I think, to facilitate it and make that smoother. The people that I've talked to that generation outside, they are pretty comfortable with that right now, and let's just get that as an incremental step working before we consider the other thing because you just don't really want the political heading, fighting, and rationalizing why renewables Pine River or wherever should count. Those are my brief comments. I appreciate the time.

PRESIDING MEMBER GEESMAN: Thank you, Steven.

MR. LEUPP: Good afternoon, my name is Alex Leupp. I am before you representing the Northern California Power Agency. We made up of 16 (indiscernible) power communities, irrigation districts, cities.

I wanted to briefly talk about what renewable portfolio standard programs we are doing. We definitely take our commitment to renewables very serious and any implication that we are not doing our fair share, we disagree with.

Every single one of our members are local governing bodies consistent with 1078 have adopted RPS standards that are tailored to their individual communities. In many cases, our member utilities are already on track to meet and exceed the 20 percent goal with or without counting the large hydro.

Other members have set RPS goals that are more ambitious than those currently required of IOU's.

While for profit utilities have been arguing over procurement rules at the PUC and as a staff reports states on page 83, the percentage of renewables in the IOU power mix is actually fallen in recent years, and CPA members have been expanding their renewable portfolios in some cases in spite the fact that they are fully resourced.

In Santa Clara, Silicon Valley Power has recently contracted with PPM Energy in Portland, Oregon to purchase approximately 75 MWs of wind energy a year for the next 20 years. Deliveries under this contract are expected to begin January 1, 2006. The amount of wind energy to be added is approximately equal to six percent of Santa Clara's current sales. The six percent will be in addition to their current power mix of 24 percent eligible renewable resources. Not only is that amount of renewables nearly double that of the surrounding private utilities' portfolio, but it comes with a savings of 30 to 40 percent for Santa Clara's ratepayers.

Palo Alto, another one of our members also supports the deployment of renewable energy supplies through photovoltaic rebates for its current customers. Palo Alto has provided over one million dollars in this to date achieving over 100 systems and 315 KWs of installed capacity, one of the highest per capita shares in the state.

Palo Alto is also matching a grant from the U.S. Department of Energy to install an additional $2.8 million worth of photovoltaic systems in city facilities. The systems will approximately double the installed solar capacity inside Palo Alto and also expected to be on line in 2006.

Redding Electric Utility, another one of our members, has recently signed an agreement for delivery of approximately 90 GWhs a year of wind power, which is also set for delivery in 2006. This would more than quadruple their current percentage of eligible renewable resources to approximate 117 GWhs, equal to 14.1 percent of Redding's retail sales.

In tandem with our agreement, Redding Electric Utilities actively seeking additional renewable resources from two separate parties with delivery dates ranging from 2006 to 2008, 2008 with the anticipated addition of these two resources, Redding expects to deliver approximately 28.4 percent of retail sales from renewable resources. Again, this number does not include large hydro.

Roseville Electric is another great example. Despite the fact that they are currently constructing the Roseville Energy Park which is a 160 MW baseload combined cycle plant, they have taken the extra step of including a 1 MW solar facility at the plant site. This is a great example of public power taking the initiative without a legislative mandate.

Roseville also offers their customers a $4 a watt incentive for solar power which brings the price of installing a solar PV system for a homebuyer by as much as $10,000. In addition, the City of Roseville partnered with Premier Homes to build the Premier Oak Subdivision, the first all-solar community in Placer County where all 49 homes are equipped with solar integrated roofed houses as part of the original construction process.

To build on the success of this venture, Roseville will be proposing a city ordinance called the Best Homes Program. The program will require a 10 to 20 percent of all new home construction include integrated solar rooftops, on demand solar heaters, and energy efficiency measures that exceed Title 24 by 30 percent.

Here are the few examples of what we are doing. I just want to address the initial comment that there is this worry that Municipals are not participating or doing their fair share, so I just wanted you to know some of our best examples.

PRESIDING MEMBER GEESMAN: I appreciate that, but let me also share with you the observation that there is no rest for the weary, and I think that the pressure that you've experienced to date in this area is bound to only intensify. I think that the Legislature codifies the 2010 goal that the regulatory agencies have embraced since 2003, there is going to be a lot of pressure brought to bear on the municipals to accelerate their 2017 targets to match the investor-owned utilities.

As I think you know, the governor and this Commission have embraced a 33 percent goal for the year 2020. I think that also to the extent that global climate change becomes a overriding rationale for the state's commitment to renewable energy sources, there will be even more pressure brought to bear on the municipal utilities to match the performance of the investor-owned.

In so many other areas, the municipal utilities have been able to persuasively claim to be better performers, and right now as you are well aware, there is a perception that the muni's are laggards in this field. So, I say that as probably your strongest advocate on our Commission and certainly as one that is not in favor of the one size fits all approach that some of our colleagues on the other commission from time to time give voice to, but the pressure is going to grow.

MR. LEUPP: I am aware of that, and as you know, perception is not always reality. We have to do a better job of telling our story because we do believe that we are actually leading the state and not the other way around.

PRESIDING MEMBER GEESMAN: I appreciate your comments. Others in the audience? Gary? Barbara, you're next.

MR. SCHOONYAN: Gary Schoonyan, Southern California Edison Company. I am not going to repeat a lot of the comments that I've made before at this Commission and other commissions. I was going to comment on a few things, though. One is that -- and it kind of piggybacks off, I think, the exchange that you had with the chap from NCPA is that basically the obligations need to be equivalent whether you are investor-owned utility, a CCA, or a municipality, they need to be equivalent.

I am not suggesting that we need to tell the municipalities and others how to do their job, but basically the objectives and the goals should be the same.

With regard to a couple of the discussion or a little bit of the discussion that started earlier with regards to success rates, I am not sure how many of you are around in the mid 80's when the initial interim standard offer 4's and interim standard offer 2's were there, but I was. A number of these projects were really flaky projects. There was no due diligence done on them.

I think the fact that there was only a

67 percent success rate speaks for the types of projects that were proposed. Many of them came to fruition and have provided good renewable power, but a large portion of them and all you had to have done is seen some of the pictures or visited some of the sites, and they were pretty hysterical, some of the configurations these chaps had come up with.

Going forward, there is significant due diligence with regards to renewable procurement. The only project that we've entered into, and I think one that Mr. Kelly mentioned that did not go forward, was the one that basically required the Public Utilities Commission approval to transfer land from PG & E to this particular developer for 100 MW biomass facility. It was actually a transfer of land, and Mr. Kelly didn't mention this, but I believe there was a governor's executive order that gave the approval for, but still the Utilities Commission turned it down.

I think going forward, the success rate, given the due diligence that goes on in the negotiations and what have you is going to be significantly greater than the two-thirds that was experienced from the initial contracts.

There was also some discussion with regards to sanctions, and I thought it was pointed out quite well by those on the dias that we are confronted with a five cent up to $25 million penalty associated with this. Any increase sanctions just doesn't make a lot of sense.

Mr. Kelly talked about increased sanctions as being a way to insure that we move forward and keep going. I am sure he wouldn't be upset at all if we put that in our contract from here on out for lack of performance that amount of the sanction money comes out of the supplier's hide and not our utility customers or shareholders.

Finally, there was a little bit of an exchange with regards to the availability of contracts, the long term contracts. To my knowledge, we aren't holding those back. I mean to the extent that the developer that has entered into a contract with us wants to make his contract available, we don't have a problem.

To the extent those that lose in the contract negotiations want to make their contract available, it is their contract, it is their proposal, they can do that. I am not sure that, hearing Mr. Kelly talks like they have no problem doing it. I guess what I am saying is I'm not aware of any problems we have with regards to these long-term arrangements coming forward.

To the extent that they require PGC funds in the form of a SEP, that's something that this Commission ought to frankly insist upon before they get it, they have an understanding of what that arrangement is.

PRESIDING MEMBER GEESMAN: Gary, revisiting that five cents a KWh, I take it that you regard that as a fairly serious potential penalty?

MR. SCHOONYAN: Very serious. I mean we've gone out for two solicitations, both of which the arrangements we signed have the potential far exceeding the one percent. The latest one that was mentioned was 142 MWs, which at the bear minimum, that was a minimum, is about 600 Gwhs per year. That is expandable up to almost two billion KWhs a year.

There is upward movement on that particular arrangement. We are going to be going out for another solicitation this September. Now, talking about this solicitation, that last one, there's been some discussion about how long it took. There was horrendous contract problems. The EEI format, the daggum exceptions to that particular contract were bigger than the contract.

It got to the point we said, this is nuts, and so we came up with a new pro forma contract that is financable by Wall Street. That is what we are going to be using going forward, and I would like to believe that these solicitations will go a lot more smoothly in the future as a result of that.

PRESIDING MEMBER GEESMAN: You are not relying on the PUC waving the penalty when we get to 2010?

MR. SCHOONYAN: I'm not relying on that, no.

PRESIDING MEMBER GEESMAN: On projects that haven't gone forward, part of the charm of our non-transparency is that commissioners here never see those, but based on what I've read in the newspapers, wasn't there something called "true solar" that was supposed to come here for SEP's and never showed up?

MR. SCHOONYAN: That was some time ago, correct.

PRESIDING MEMBER GEESMAN: Okay, that one didn't go forward, did it?

MR. SCHOONYAN: Fortunately not.

PRESIDING MEMBER GEESMAN: Thanks a lot.

COMMISSIONER PFANNENSTIEL: Gary, Steve Kelly mentioned a couple of times that he finds that the utilities have drastically understaffed the renewable areas. Do you think that is the case at Edison?

MR. SCHOONYAN: No. I mean there are quite a large staff, and a lot of it has to do, and it gets back to these penalty incentives, and it is not the five cent. It is things that there used to be every year when we would go through an annual reasonableness review, there was anywhere from 50 to 300 million dollars of penalties assessed against us for our contract administration.

When you have that sort of potential down side associated with these contracts, you staff up. The staff is still there, and it is still very much of a concern, but the biggest problems that we had in going forward were the contractual problems.

I would also like to point out I'll be

very interested in seeing IEP suggestions on legislation next year to replace SB1078. It is long, but there are a lot of elements to it. Obviously one of the elements has to do with the transmission, 399.25 comes to this trunk line concern. We are going to be working with the Utilities Commission under the intent of 399.25 to move forward with that going forward.

There were provisions and they are quite lengthy, but there were provisions within the statute and the foresight to basically figure out there may be instances where the state has to back stop where the FERC is not going to perform.

COMMISSIONER PFANNENSTIEL: A slightly different issue then, you don't think that the MPR SEP provisions adds really to the time that these contracts have taken. You don't think that really gets in the way.

MR. SCHOONYAN: I believe it probably does, primarily from the proposal perspective. The poor developer has to figure out what the bid is, what is going to go to the Commission with. I don't know what the developer goes through or not, but I would have to believe that adds a little complication and time associated with it.

To the extent that if it is the decision of everyone to do away with that and give the 135 million back to the customer and just do bi-lateral arrangements, I think that is something we would think positively to.

COMMISSIONER PFANNENSTIEL: Have you done any analysis about that, or that is just a policy analysis?

MR. SCHOONYAN: This is the first that I heard of it today.

COMMISSIONER PFANNENSTIEL: Thank you.

PRESIDING MEMBER GEESMAN: Gary, tell me on 399.25 focus on the Tehachapi Segment 3, if that project ultimately ends up being primarily for the benefit of San Diego Gas and Electric and PG & E, how do you avoid your ratepayers getting stuck with disproportionate share of the cost if your source of recovery is retail rates?

MR. SCHOONYAN: We are still thinking through it, but basically there would be. Even though with the open access and what have you, there's still point to point transmission service. What I would envision happening, either the developer would have to, through their contract or the purchaser, some how reimburse our customers for the amount they are using that. It wouldn't be on as available basis, it would be firm basis for the amount of MWs involved to get to the ISO grid.

PRESIDING MEMBER GEESMAN: Thank you. Barbara?

MS. GEORGE: Barbara George, Women's Energy Matters again. Good afternoon. Two years ago I think it was that I was at a (Indiscernible) Seminar Intentional Conference, and President Peevey said I don't think RPS will every work. So, I haven't put a whole lot of faith into it. I've been looking for other solutions, and community choice is one of the solutions which I think is very promising.

I do want to point out --

PRESIDING MEMBER GEESMAN: How well has that worked in the last two years?

MS. GEORGE: There is a stalling and delaying problem which Mr. Peevey who was in charge of the proceedings, and I wish he would hurry it up a little bit, but it looks like it is going to come to a decision on rules in September. So, we have about 40 to 50 cities and counties around this state that are very interested in going forward with them.

Your Commission funded the Navigant study which showed that they can go to it turned out 50 percent renewables with no rate increase, which is an incredible wonderful prospect.

I did want to mention, though, that we have an eery parallel with the early 90's, the earlier integrated planning process with the stalling and delaying of renewable energy, and at the same time a huge new energy efficiency budgets. The same thing happened, Bill Marcus from JBS did a study on that time period, and he tracked the energy efficiency budgets and found that the moment that FERC killed the wind contracts with Edison and PG & E, that the month after that, they just slashed their energy efficiency budgets and fired their staff.

I certainly hope we are not going to see anything like that, but I do think we need to be watchful when the utilities are saying that they are so supportive of the loading order and the energy efficiency and renewables, but we don't see them somehow being able to step up to the plate and make it happen.

I think we need to remember that we have utility owned power plants, transmission projects, liquified natural gas, coal, nukes, and transmission all waiting in the wings, and the utilities would be potentially making a lot more money off of those things than they will ever get off of the renewable energy.

I notice that the reports --

PRESIDING MEMBER GEESMAN: I am not certain that I accept your premise there. Now why is that, that they would be making a lot more money off of those other things from renewables?

MS. GEORGE: They get a high rate of return on construction for one thing, both transmission and power plants --

PRESIDING MEMBER GEESMAN: Including renewable power plants?

MS. GEORGE: That's true, but we don't see them building them in very much quantity, so that is where they look at renewables, just like they look at energy efficiency like it is a little number, and the fossil fuel is a big number. So, I think their focus tends to be on the big number. That is the experience that I've had in transmission and power plant proceedings, is that they just dismiss energy efficiency and renewables because it doesn't count for much.

PRESIDING MEMBER GEESMAN: If I were a CFO, wouldn't I consider say an investment in a gas-fired plant as something where 70 percent of every revenue dollar went to the gas supplier, not to my shareholders in contrast to my investment in a wind farm where at least hypothetically because it is entirely capital, not expense, 100 cents on every dollar would float through to my shareholders?

MS. GEORGE: I'm not sure that I understand what the thinking is. I know that there are some utilities in this state that are selling gas or potentially would be selling gas with the LNG. So, perhaps that influences some of them. I have never understood why they don't think that it is a comparable return, but I don't believe they do. I think that is a very interesting question about why they do.

As I said, my experience in the proceedings where I have addressed this issue has been that they just don't think that it comes up to a bar that makes sense to look at. That is one of the problems with the way we have looked at renewables. I think there was a comment before about when Mr. Kelly said why are we looking at it just one percent of the time. Why aren't we thinking bigger, and I think that is where the CCA's are thinking bigger.

They are also thinking in terms of locally based NOG supplies to some extent. I mean a CCA can obviously buy something off of transmission line from wherever too, but one of the things that I think we need and that a lot of people are talking about is the local energy security, and that means a number of things.

One thing is that we don't be dependent on LNG from who knows where, but also the security of the grid itself if you have renewable generation locally, it tends to support the grid. That is helpful. It also I think is very reassuring to people. I know particular women, to know where their energy is coming from and having it be local.

That is one of the reasons women in particular support solar energy so strongly. I think it is really not the case that there isn't any renewable resources in Northern California. Even in San Francisco there is a solar energy resource. It tends to be in the southeast part of the city where the fossil fuel plants are now located. In fact, there is also wind in San Francisco. I've been talking to a few people about that, and everybody thinks I'm totally nuts, but every summer afternoon I've ever been in the Bay Area, I see the wind blowing fog over the hills, and I know up here in Sacramento, you benefit every afternoon except for about three or four days in the summer from the wind in San Francisco, and that comes all the way up the Delta.

I think there's an immense amount of resources, and solar resource is very important. In the city, what the Community Choice Project is looking at is 30 MWs of wind -- I'm sorry 30 MWs of solar, and I want you to just picture it because it is a little differently from what most people have done in terms of siting solar. It would be publicly financed as Mr. Freehling discussed, but rather than asking a homeowner or a business to put up the money or half the money to put it on their building, we are actually talking about the city would rent the rooftop, the city or the ESP would continue to own the solar until it is paid off. It would be used on the flat roof in the Bay view to run whatever that business is underneath it so it would not basically be going, you wouldn't be worrying too much about net metering and having it go out on the grid.

The other issue there, of course, is that you are able to avoid some transmission and distribution upgrades by using the power right there where it is located.

So, I think this is where the CCAs are looking at these types of things. It is a different point of view from the giganticness of the system that we have been building for the last couple of decades. We were thinking larger and larger and longer and longer transmission lines, and I think that there is a counter balancing force where, hey, what's possible to do right, right here close by. I think that we could have a conversation with PG & E about the fact that they don't see a possible resource in Northern California because I think that there is one.

Mr. Freehling has also produced some figures if you look at the long term financing potential, your cost is getting to be very competitive over the period of time. That is why the CCA can offer a 50 percent renewable energy with no rate increase because unlike the utilities who are going as slowly as they can, the CCAs would go as fast, the CCAs and the ESPs I might add, would go as fast as they can.

PRESIDING MEMBER GEESMAN: Thank you very much. Other comments from the audience?

MR. ZETTEL: Good afternoon, Commissioners, my name is Nick Zettel with the City of Redding Electric Utility. I have a few comments to follow up on with what Alex said from NCPA.

We realize the pressure, we realize the pressure to reduce dependence on fossil fuels and the global climate change pressure. As far as time wise, we have discovered through our negotiations is working bi-laterally with credit worthy parties produces decently times and decent times to contract negotiation, much like a regular power purchase agreement would.

I work in the Division of Resource Planning and when we look at adding renewable resources, there is some constraints that we are faced with, especially as a smaller municipal utility, we have a peak load of about 245 MWs, so we are not up on the big fish level.

One constraint that we see is that our load only grows so quickly. Another constraint is existing contracts that were signed previous to RPS legislation only expire so quickly, a third constraint is your existing steel in the ground, your generation can only be so flexible if you install base load units thinking this was going to be your primary mode of service and then renewable resources come along, and they act more as a base load, a lot of them, then you have to back down your units and do some operational things.

Transmission capacity is always an issue. There is only so much to go around. You have to decide what you want to put on the line.

Another thing we realize in resource planning is that renewables don't meet all of your future growth needs. There is some shaping issues, answering service issues load following ramping, and what we have seen, especially with our wind contracts we've recently entered into is that when they are shaped, they are put into block products for you. So, when they come down the transmission lines as a base load product, and so you have to have some other either gas or other resources available to move around. So, that is another constraint.

We have seen that these are grade based load products, and they are a fixed price which provides an excellent fuel price hedge long term. They are a great addition to your resource supply portfolio, and we think they are going to play an important role in future supply. Any way you want to choose the gas price forecast, renewables are going to be fairly competitive. I just thought I would add a little bit more comment to Alex --

PRESIDING MEMBER GEESMAN: I want to thank you for doing that because I think you make a number of good points. I do think that the renewable portfolio standard when conceived in the Legislature and also when developed nationally as a proposal by the various public interest groups that sponsored it some number of years ago, had large portfolios in mind. It is much much more difficult to achieve an appropriate balance in a smaller portfolio which is why this commission last year in our 2004 IEPR update recommended a case by case variance procedure for smaller municipal utilities as opposed to the one size fits all approach that our colleagues at the other commission have advocated and which receives a fair amount of discussion in the Legislature from time to time.

I'll note that since we recommended it, I haven't heard it mentioned a single other time which reinforces what I said to Alex, this pressure is only likely to grow. It is not likely to diminish going forward, and I think you need to continue to make the observations that you have shared with us today because things designed for the bigger fish don't necessarily fit the small fish especially well.

MR. ZETTEL: Every utility is going to try their best within reason with their rates and existing generation and contracts, and we just wanted to make sure that the Commission realized that municipal community was working hard to make sure we all meet the goals in mind.

PRESIDING MEMBER GEESMAN: I appreciate your remarks.

MR. ZETTEL: Thank you.

PRESIDING MEMBER GEESMAN: Other comments from the audience.

(No response.)

PRESIDING MEMBER GEESMAN: All right, why don't we go then to distributed generation.

MR. RAWSON: Good afternoon, Commissioners, members of the public, and staff. My name is Mark Rawson, I am going to present the Distributed Generation issues that were covered in the loading order paper.

The fact that I am standing here obviously means that my wife is not delivering at the moment, so I won't have to depart the group, but we will see if we can get through this quickly.

We have covered the other three parts of the loading order this morning and early this afternoon, and I want to point out that from my perspective, distributed generation is one of the most strategic loading order resources. When I make that statement from the perspective of when it is implemented as a combined heat and power application, it provides cost effective end use sufficiency for California's customers that have and can have significant greenhouse gas benefits.

When it is fueled with renewable fuels, it can help us meet us our renewable energy goals. Once installed in peak shaping applications, it can be used effectively by customers as a demand response strategy. The fact that we are going to talk about it last, I think, is pertinent when we consider its role in the other parts of the loading order.

There has been principally two key issue areas addressed in the '05 loading order report with respect to DG, these being, looking at more transparent distribution planning and what role distributed generation as well as demand response play in that process, and issues that affect both DG and larger generation systems in the area of combined heat and power.

Staff conducted two public workshops that this committee hosted back in late April that spent two days talking about these two specific issues, and there is a wealth of information in the loading order paper around these two subjects, but I am going to cover just a couple of topic areas in today's presentation.

I think two things that are worth noting here is that in the process of looking at these issues, staff was not constrained to just what is going on in California. We looked at what is going on around the nation with other utilities and states, and we even went so far as to look across the Atlantic to see what's happening in

Europe with respect to distributed generation and its implantation into utility practice.

Some of the work that has been done in this area, we looked at distributed generation and combined heat and power from multiple perspectives. By this I mean we did analysis that looked at it from the specific DG customers perspective, the utilities are non-participating customers perspective as well as society's perspective.

I am first going to talk about distributed generation, and then I will shift gears a little bit and talk about combined heat and power. Distributed generation has no explicit mandate in California. There are no explicit capacity or energy goals for distributed generation, yet it does serve a significant role in various policy documents including earlier versions of the policy report and the current version of the Energy Action Plan. It has a significant role looking at the promotion of customer and utility-owned DG.

There is various pieces of legislation have been passed that all show a preference for distributed generation in comparison to the traditional central power plant paradigm.

To date, there is about 2,500 MWs of installed DG capacity in California. This statement is made with the working definition that we've been using that distributed generation is power generation located close to the load center that is interconnected the utility system at distribution voltages. By practical purposes, that tends to mean that it is less than 20 MWs in size in order to be interconnected at those voltages.

The state has made some significant successes in addressing barriers. I just want to highlight one here in the area of interconnection rules. We are working collaboratively with the Public Utilities Commission and the Energy Commission has worked with utilities in industry, DG industry to develop a streamline interconnection rule for California that was implemented in late 2000. We are seeing the benefits from that effort, not only are these streamlined rules in place now with the investor-owned utilities, but we are seeing municipal utilities around the state also taking advantage of the streamline interconnection rule development and implementing it within their service territories.

These two charts show some of the benefits that have been derived from addressing interconnection rules. You can see that in late 2000, when the rules were realized, we have seen a drastic reduction in the number of days it takes for an interconnection to occur. We have also seen a dramatic reduction in the days past when it was requested to be online.

The savings associated just with the interconnection costs we've seen between the period of 2001 and 2003 upwards of $34 million interconnection cost savings to DG customers.

PRESIDING MEMBER GEESMAN: Mark, do you have any idea how those interconnection times compare with other states or other utilities elsewhere in the world?

MR. RAWSON: I do not have a good answer for that.

PRESIDING MEMBER GEESMAN: Other than saying that they've improved in California, how can the Committee know if those are good numbers or still numbers that have substantial potential for improvement.

MR. RAWSON: Let me address the 2000 data that is shown here. We did not have a good base line on how long it was taking to interconnections in California until the Energy Commission and the utilities and DG industry began working together to revise these rules. DOE funded a study through NREL about that time that looked at interconnection processes around the country, and we derived from that study -- we took from that study the California specific data to created a baseline that we could use for comparative purposes to how we are doing in California since we revised the rules.

I can say that the interconnection days that are shown here in 2000 are indicative of interconnection times that were seen in the other states that were investigated in DOE's report, which I believe included New York, Texas, and there is one other state, I can't remember at this point.

I ant to shift gears a little bit and talk about CHP. With respect to CHP, these issues are broader than just distributed generation that I mentioned using our 20 MW definition earlier. Again, here, California has no specific mandate for CHP resources, no explicit capacity or energy goal has been established for combined heat and power. Despite that, there is approximately 90 to 100 MWs of installed CHP capacity in the state. About 40 percent of that is in systems that are greater than 100 MWs in size.

In the smaller range, less than 5 MWs that constitutes about 3 percent of this number. So, you can see that the majority of it is the large systems, and a good portion of those are systems that operate as QF's, and, of course, there is this issue of whether or not there contracts will be renewed with it. Utilities which is a subject of current CPUC proceeding.

What is important to note about these particular resources is they provide about 15 to 20 percent of peak demand in the state, so they are an important resource for California.

Through this '05 IEPR, we hired a consultant to take a fresh look at what the technical potential was still available in California. We hired every and several of their consultants, energy and environmental analysis, energy and economic analysis to do an assessment of the California CHP market and to go a little bit farther and look at some policy options that could be implemented to increase the penetration of CHP in California between today and 2020.

What they found in that update is that there is about 30,000 MWs of technical potential still remaining in the state. I need to caveat that technical potential is in no way an economic forecast. When you start to consider the economic potential, that number becomes less, but it does provide a good benchmark against what potential is still available in the state that we should be aware of.

What we did find, and I am going to talk a little bit in the next slide is that there is about 5,000 MWs of untapped CHP potential existing today with large end use customers. I'll cover that here in this next slide.

Policy scenarios, there was about seven policy scenarios that were evaluated that looked at different implementations that can be made in the state and what the impact of those implementations would be at increasing the CHP potential. What that analysis found and some of the more aggressive policy scenarios that upwards of 7,200 MWs of additional market potential for

CHP existed.

These two charts taken from the consultant's report that I alluded to show that there is about two-thirds of the remaining technical potential for CHP is really in the commercial and institutional sector.

Potential from new facilities in the state is about 20 percent of this 30,000 MW technical potential. I mentioned on the previous slide that there was about 5,000 to 5,200 MWs of export potential in the state. These are very large facilities that are comprised of the top 100 industrial facilities with large steam demands in the state. So, this is a handful of very large refineries, chemical plants, and food processors.

One of the policy scenarios that you will see on the next chart really gets at the issue that these facilities have at providing additional CHP in the state, and that is what to do with their excess electricity production.

If these facilities were easily able to export their excess electricity and actually size their systems to meet their on-site heat loads, we could get at this additional 5,200 MWs of CHP potential at these existing facilities.

The difficulty that they face is that selling excess electricity in the wholesale market is somewhat complicated. It requires scheduling hour with the Cal ISO and arranging for a buyer of that electricity and the metering that is required to comply ISO tariffs, the industry has indicated can be expensive and can actual kill projects has been one of the barriers that has prevented the state realizing this addition MWs of CHP.

This chart is a little bit of an eye chart, but I will not cover all of it, but I think it points out some important themes that I would like the committee and the public to take away and comment on. This is out of the CHP analysis that was done by EPRI and its consultant team.

Across the bottom here are the different policy scenarios that they evaluated, the base case basically reflects if nothing changes -- if everything remains as it is today in terms of policy regulatory structure, then it moves across to the right to more aggressive policies that require more implantation of either rules or regulations.

On the left hand vertical, this shows the net societal benefits in millions of dollars that can be achieved through these different policy scenarios. On the right vertical is the cumulative CHP potential in MWs that could be achieved from each of these policy scenarios. For example, in the base case here, we see that there is about 2,000 MWs of CHP potential that can be reached if we make no changes between now and 2020.

As you move towards the right hand side of this chart, you get to this point here where the whole issue about exporting excess electricity into the wholesale market really starts to have a significant impact in the penetration rate of CHP in the state.

This is where we really start to see not only CHP penetration, but we also start to see that the net societal benefits of CHP adoptions in the state start to become quite significant.

Another take away from this chart that I want to point out is that in all of these different instances based on the analysis by EPRI and this team, in all the different policy scenarios, you will notice that here on the bottom in these purple bars is a representation of the effects to the utility. The take away here is that in all of these instances, this is a revenue loss for the utilities. That is an issue that I think is worth pointing out and that is going to be one of the questions that I am going to pose later in the discussion.

PRESIDING MEMBER GEESMAN: Mark, my recollection from the April workshop was that the CHP industry was critical of the numbers in this report for not reflecting a beneficial impact on the price of natural gas.

MR. RAWSON: I'll have to go back and look at the specifics, but I do believe they did consider some elasticity effects between gas and electricity and how that will effect gas prices.

PRESIDING MEMBER GEESMAN: These numbers are unadjusted from the material presented in our April workshop?

MR. RAWSON: That is true, they are not adjusted.

These next four slides I'm going to highlight four key issues that I'd like to solicit comments from the public on with respect to distributed generation and CHP. The first of which is this issue of payment for service versus incentive.

In the consultant report, they hypothesize that moving away from an incentive based structure to a performance based structure should ultimately increase the penetration of CHP and have higher efficiencies than the central station paradigm.

It should decrease losses to the utility and non-participating customers relative to the incentive approach. It should provide a clear exit strategy that ultimately will eliminate all incentive programs and pay for the benefits or services that both distributed generation and combined heat and power provides.

It will achieve higher societal costs because customers and utility benefits will be provided for, and that there will be less resistance from stakeholders that increasing subsidies through payments, they are basically going to match the benefits to the services that are provided, and that therefore, they will be a low impact on rates.

The key question here is whether or not California should move more towards this payment for service rather than incentive structure and whether or not the points in this hypothesis are actually true.

On this next slide, it was alluded in the consultant report that these principal policy options would have the greatest effect on both DG and CHP penetration in the state. The first one I have mentioned previously is enabling electricity export, particularly for the large CHP installations where they could sell their electricity directly to the utility that is servicing them. This approach could be something similar to net metering, but it would be net metering at the prevailing wholesale electricity price.

The next one is the implementation of payments for the transmission and distribution benefits that DG and CHP provides customers. That this could be done through operating agreements with the utilities with the requirements for physical assurance being met. That this could be targeted for areas of the state where we have capacity constraints.

Providing payments so that these systems are available when the system most desperately needs them. This would have the affect of improving resource adequacy. The last one being that payments could be provided for the CO_2 emission reductions that CHP provides to the state. This could be done through some form of production tax credit.

So, key questions is whether or not these options are feasible. If they are, how should they be implemented and whether or not we are missing any potential policy options that should be pursued.

Shifting gears a little bit here to planning tools. We spent a better part of the day talking about how the utilities do distribution planning in California. We looked at what some utilities around the country are doing in integrating distributed generation and demand response into their planning practices.

A key question here has to do with some of these new planning tools that are coming out of research and that are being embraced by progressive utilities around the country.

Detroit Edison was one utility that we highlighted on April 29th, and they really made a corporate commitment to distributed generation, and many facets have incorporated into how they do their business. They look at both utility-owned and customer-owned distributed generation as a means of meeting their system requirements.

There is some research that has come out of the public interest energy research program here, namely one project with new power technologies that looked at a new approach for assessing how distributed generation and demand response can benefit the utility system.

What that research showed is that distributed generation and demand response at most customer sites in this first phase provides some level of utility benefit. So, a key question here is what are the implementation hurdles to using this type of approach and how can we resolve those hurdles.

DOE has done some very interesting work in this area as well. I mentioned it earlier in today's discussion. They are doing some work through the Gas Technology Institute. They have some some initial work on Detroit Edison's system, and now they are in a second phase looking at Southern California Edison's system where they are looking at how a portfolio approach or an integrated approach of distributed generation demand response, CHP, and energy efficiency can be used to reduce the peak load on the distribution system, on particular feeders in the distribution system, and how that can defer investment in distribution.

We should look at how those approaches can actually be implemented here in California as well, and we have some questions about how best to do that.

The state is looking at distribution system where investments have been delayed because of uncertainties in the energy market. We are hearing that there is billions of dollars are going to be invested over the next few years to get the distribution system back up to snuff. A key question I think that we want to pose is whether or not we should continue to build the system the same old way, or if we should be looking at new approaches and new designs that actually enable some of these non-wire solutions such as demand response and DG, etc.

I mentioned earlier in the earlier graph that when we look at CHP policies, one of the key issues or take aways is that distributed generation and CHP can be a revenue loss for utilities, and I think a key question that needs to be addressed is how can we address that. Should the utilities be given regulatory incentives to take a more proactive role in the implementation and promotion of cost effective DG and CHP? Should we be looking to other regulatory models that have been tried in the area of efficiency in the form of earnings rate adjustment mechanisms as one of those regulatory incentives as a way to get the utilities down the road of promoting distributed generation.

In the area of monitoring an evaluation, we don't have a good tracking system in place today to keep track of the capacity and energy that is being produced by distributed generation and combined heat and power in this state.

If we are going to rely more and more this particular component of the loading order, we need to get a better idea of how much capacity is going in, how much energy it is producing so that we can keep track of whether or not we are contributing to the implementation of these resources.

I should note that the whole issue around reporting is a subject of the current DG proceeding at the CPUC that Energy Commission staff is collaborating on. We have tee'd up this issue of information reporting by the utilities. There is a variety of different reporting requirements that the utilities have to meet today that range from interconnection reporting to (indiscernible) reporting to cost responsibility surcharge reporting, so we are going to be working with the CPUC staff in the next few months to hold a joint staff workshop to look at what the different reporting requirements are for the utilities today and look at how that can be streamlined as well as how we can get some of this reporting incorporated into that process so that we have the ability to keep track of what capacity and energy is being produced provided by DG.

Some key questions here that we want to pose to the public is how can reporting be accomplished so we can measure DG, how can we do that cost effectively. At the same time, how can we respect the customer's confidentiality issues about how they are implementing DG and using DG to meet their particular needs.

I will forego the other 57 slides that I have on DG and conclude my talk.

PRESIDING MEMBER GEESMAN: Mark, do you

think the position of DG and CHP within the loading order is particularly well understood?

MR. RAWSON: I think that as it was alluded to by some of my previous staff colleagues that have presented, when we look at these resources, we tend to look at them in stove pipes. We look at efficiency, and we look at demand response, etc., but when you really start to kind of unpack distributed generation and how customers use it, it really can be an interval part of the other parts of the loading order resource.

I don't know if that answers your question, or maybe you could --

PRESIDING MEMBER GEESMAN: Let me try it again, and let's strip away the renewable DG, let's put that in a category of renewable generation, which I think the loading order is pretty clear is behind energy efficiency and demand response. Somewhere between renewables and conventional fossil-fired generation, it seems to me that CHP and fossil DG float fairly ambiguously. I'm not certain that it has been clearly communicated to the utilities. I certainly know that every time the subject comes in front either this Commission or the Public

Utilities Commission, and it does occasionally in our Energy Action Plan meetings, everybody stands up and salutes this is the greatest thing since apple pie, we are all in favor of CHP, but I don't know that translates very effectively into policy if you observe some of the actions the ISO has taken with respect to their metering provisions.

I am not certain that it translates particularly well in terms of the contracting activities of the utilities the way they have structured their solicitations, the questionable renewal status of the QF contracts. I don't know that we have served our own interests well by being as vague and perhaps ambiguous as the existing Energy Action Plan loading order is. I am reflecting on that April 28 workshop that we had. We've got quite a bit of complaint from the CHP and DG industries about that ambiguity.

MR. RAWSON: Yeah, I would agree with you. I mean, you know, CHP is one of those applications of which DG is a small subset. CHP can be quite larger than distributed generation, but really CHP is an end use efficiency measure. Its role in energy efficiency I think could be somewhat buttress, but it does not have -- the fact that it does not -- that we don't have a definitive goal established for either CHP or DG in California, I think is problematic.

You know, some of the concerns that were raised by the CHP community back in April that you alluded to, I get the sense that they feel like they are trying to meet their end use customer needs, in this instance heat, some of the comments that we got from them is we are not power producers. Yet, some of their comments seem to indicate that they feel like their treatment with the utilities, that they are power producers and electricity producers. So, I think, you know, between the utilities and the DG industry and CHP industry in particular, there seems to be a disconnect there.

PRESIDING MEMBER GEESMAN: It would strike me that if these projects went away, we would have an awful lot of new load to serve, new demand for natural gas from less efficient units.

MR. RAWSON: One of the parts of the discussion that we had on April 28, we put together an end user's panel, and we had representatives from the CHP community talk about their experiences, and there was a fairly equal representation of large and small CHP practitioners in the state, and some of those folks conveyed that they had CHP at one time, and that it really wasn't in their core business area, and that dealing with it was complicated. In some instances, they actually removed it and installed traditional boilers to deal with what their core business is, and that is providing for that heat load.

From my perspective, I think that is a terrible waste considering the efficiency gains that can be had by promoting CHP in California, not to mention the $Co2$ benefits that can be had.

PRESIDING MEMBER GEESMAN: And criteria pollutants.

COMMISSIONER BOYD: Obviously, Commissioner Geesman and I are seeing this very much the same way. You have already referenced the fact that energy recovering reuse is really efficiency and just improving efficiency and taking advantage of another resource that is already there.

I've said before, this is an area we just don't seem to be mining adequately, and after this morning's discussion and the problems and the success we are having in other high priority areas in the loading order, it just becomes more and more apparent to me that this is an area we need to push harder, particularly in this post-9/11 world where energy security has to do with energy diversity. Energy security may have something to do with a physical location of that energy, there are certain strategic or very important industries that may benefit society even more than others by applying this technology.

One, I would commend you on the report, all the issues are in here as far as I can see. I would note with the adamants with which the proponents, which one would expect, at the April 28 workshop is represented in your hearing notes, but the opposition from the utilities to this subject, some of it still masked in the old QF day horror stories is fairly apparent, making me think it must be seen as a real threat and must be quite viable.

In any event, it just sounds like these two commissioners who have to deal with this subject in the current energy report obviously feel that this is an area that needs to be looked at very thoroughly, probably needs to be pushed much harder, and we need to get to the bottom of why we can't incorporate this more aggressively to California's future about which many people have a lot of concern right now.

So, I look forward to the comments that we will hear today, probably even more so to reading the written material that we are likely to get as we formulate our views for the energy report.

MR. RAWSON: Thank you.

PRESIDING MEMBER GEESMAN: Thank you. Comments from the audience?

MR. AOKI: Good afternoon, Commissioners and members of the panel. My name is Rod Aoki, and I am here today for the Co-Generation Association of California and the Energy Producers and Users Coalition. First of all, Commissioners, I'd like to thank you all for this staff report, which I think goes a long way towards recognizing CHP as part of the loading order under distributed generation, and also for your comments today just preceding my speaking about CHP and placing it in the loading order.

We have been, as you know, involved in this process early on appearing at the very early

IEPR '05 workshops at the EAP meetings, at the April 28 workshop, and filing of comments, and we appreciate your hearing us and responding through this report.

One of the things that the slides that Mark addressed was whether anything was being overlooked, and I think this report, although it emphasizes encouraging new CHP generation, that is very good. One of the things that we think is just as important is preserving the existing resources that you have in California right now.

According to the CPUC and I had mentioned this before, CHP contracts are expiring at a significant rate over the next five to seven years. 1,000 MWs by 2008 and 1,800 MWs by 2010, and I think that 1,800 MW number is very close to the 2000 MW base case that is being looked at for promotion of new.

As you know and as was mentioned briefly, absent continuing operation of these facilities, you kind of need to look at the flipside of all the benefits that CHP provides, and they are outlined so well in the report, loss of the capacity, loss of location of capacity where there are transmission constraints, the need to serve on-site load from the grid, transmission issues, natural gas forecasting issues, and possible increases in the emissions, in fact, definite increase in emissions.

That meeting a couple of weeks ago, the 46th meeting of this Committee, I think this was reference to this is "crunch time" for the '05 IEPR. I am here to express to you that it is also crunch time for CHP projects, large industrial CHP projects that have contracts expiring. Without the help of this Commission and the CPUC, we just don't think it is at all clear that preservation of this existing resource is guaranteed for California.

To give you just a couple of examples as was referenced here and as the report states, there is one facility that could not extend contracts, abandoned its CHP and installed boilers. I believe that was a buried petroleum facility that is on the record.

There is also currently right now a 300 MW CHP facility in Southern California which has a contract expiring on August 9. It has been in contract negotiations for some time, but just has not been able to negotiate a contract. As of right now, it is looking at August 9 deadline, and it is not sure exactly what it is going to be doing.

Just as importantly, there are other large facilities employing CHP right now that are in the process of making important decisions on major equipment replacements and upgrades. As was also mentioned and as the Commission is aware, these industrial facilities are not in the power generation business.

The primary interest is insuring that their industrial process can operate. If CHP does not provide that security for them, the CHP option can easily fall out of that planning process for those facilities.

So, what can this Commission do? We think adding CHP expressly to the loading order as (indiscernible), and again, we appreciate the comments that are in this report.

We also need an express reservation of existing capacity and the utilities of resource portfolios to insure that all these benefits are retained and to also insure that these facilities aren't replaced by a less efficient central station power plant.

We also need long-term contracts to insure that replacements and upgrades can take place and to encourage the building of new CHP projects.

Lastly, we need to take consideration of the unique operation characteristics of CHP. The ISO has mentioned, and that is a frequent issue that we have with them despite litigation, our continuing efforts with them to communicate that we are not merchant power plants. They seem to always want to treat us that way, and I think it is vital that the unique operational characteristics are respected as they are in the existing contracts.

We had looked forward to filing our written comments on specifics of the report on August 1, but just briefly, one of the issues that was mentioned that caught our eye when we looked at the report was the issue of the utility loss of revenue. I think to the extent that these plants are promoted or encouraged through incentives, that may be something to look at or evaluate as far as the loss of revenue.

Where a customer of the utility expends his own private capital to build out an option, to install self generation, we don't believe that there should be any loss of revenue or stranded cost recovery for that. I think that option has always been that in existence for customers if they felt the utility was not performing well or for other reasons they wanted to exit the system, they had that option. That was always something the utilities forecasted into their planning for decades.

I think when the FERC developed Order 888 and looked at industry restructuring, this was also an issue. FERC expressly said that this a customer installing self generation, we are not going to allow for stranded cost recovery in those circumstances. We will enumerate that more in our written comments, but, again, thank you for your attention to this very important issue.

PRESIDING MEMBER GEESMAN: Thank you, Mr. Aoki. I guess I feel that the single greatest deficiency in the Energy Action Plan was our inability to bring more clarity to this area, and I think many of the problems that you have identified today and at the April workshop could have been avoided had we been more careful in addressing this.

I personally don't think it will be worth our while to do a second Energy Action Plan unless we can successfully clarify these issues, and I would hope that you would convey that to our colleagues at the other commission as well.

I think all of us want to do right by the CHP industry, and I think we simply need to spend the time and effort necessary and be careful in our choice of words to send some very clear policy signals that I believe all ten commissioners would like to send.

MR. AOKI: Thank you very much, Commissioner, thank you.

PRESIDING MEMBER GEESMAN: Other comments from the audience? Les?

MR. GULIASI: Thank you, Commissioner Geesman. I actually found this part of the report perhaps the most troublesome and certainly the most allusive, and I think it really has to do with some of the issues that you raised in the questions and what we have just been discussing here.

Part of this is really kind of the level of generality that we are talking about and sort of maybe the abstract nature of the discussion in the report. I think you are right that let's say DG -- in terms of one of my problems, I don't think DG, whatever that means, is adequately defined in the report.

There is discussion about small scale distributed generation or localized applications, and then we also talk about large scale CHP applications. It seems to me like we are trying to force policy decisions coming across the board to meet all those different kinds of applications, and perhaps we need to think through this problem more carefully and identify policy solutions for one set of DG applications and a different set of policy applications for another set.

This is really a tough area, so I think you are right that DG kind of resides somewhat ambiguously between renewables and conventional generation, and perhaps we need to think this through before we start adopting a new set of goals or quantifiable standards to impose on the utilities.

I would resist your urge to do anything of the sort or to make DG all of the sudden near or at the top of the loading order until we really think through this problem.

When I think about DG from the utility perspective, I have to think about it in a bunch of different ways. First, I think about it as an entity that is responsible for acquiring power, resources to meet customer needs. Here we want to be very considerate of the cost issue. What are we paying for power. We want to make sure that we are paying a reasonable price, a competitive price for power and delivering a benefit to the consumer. I don't think there is enough discussion in the report about the cost of benefit trade offs.

We also think about DG in terms of our customer relations. It is a customer of ours who is now in the position of being a supplier as well as a customer that receives all the other basic customer services. So, we are already in a different relationship with the customer, and we are very mindful of our responsibility to our customers and to maintain good customer relations.

I have to admit here that my company has not always been very good in dealing with DG customers in terms of interconnections or the speed of interconnections, the clarity of the rules associated with interconnections, and I am glad that this Commission and the Public Utilities Commission have worked in a collaborative fashion to try and clarify some of these rules and speed up the process. I am the first to admit that we have been very poor in that regard, and I've spent too many days of my career at PG & E dealing with the problems associated with the interconnection associated with DG customers.

We are actually committed, believe it or not, rectifying that situation, and we've made it a very high priority to transform that process of our business to be more customer responsive and to find ways to deliver the benefits of DG, not only to our system but also to our customers.

There is another perspective that you need to look at, and that is from the perspective of just the distribution, engineering perspective. There are applications where DG is beneficial to our system, and we are looking for opportunities to find ways to avoid and defer investments in our distribution system, realizing the benefits of DG applications, but there are situations where DG causes complications to the distribution system, and we need to be mindful of those and work through those problems.

Again, we haven't always worked through those problems in the most beneficial manner, but we need to take a careful look at our practices and find ways to make sure we can realize the benefits and reduce the headaches associated with absorbing DG into our system. Having said that, you know, there has been a lot made of this whole issue of transparency, and this is not the most hospitable forum to object to transparency.

Transparency is in principle a good thing, but you don't want to make everybody in the world a distribution engineer or a distribution planner. There are experts who are trained in this field who know what they are doing, and we should rely on experts to help solve those problems.

Again, that is not to say that we need to clarify the rules and improve our communications with customers and make it easier for customers, but you can only take transparency so far, and I would submit that there is a transparent process, maybe not one that is adequate, but the Public Utilities Commission conducts general rate cases for virtually all of the utilities, and we submit very detailed plans about our distribution programs, our distribution upgrades, and there is an open public process albeit a CPUC process, which is mysterious to many, that I would submit is a public process that can go to some length to address this issue of greater transparency without everybody all of the sudden becoming a power engineer.

Maybe what I am trying to say here is that my company has no principle objection to distributed generation. Again, I think there are many applications where distributed generation makes sense, and we want to look at it from the perspective of the customer, from the perspective of the utility, and the perspective of what is good for society. That is really a role that you play more than the others.

To the extent that we need to be very conscious of the costs and the benefits, we need to do so, we need to be very conscious of the rate impact. We know that customers want more renewable power, but we also know that customers are very conscious and concerned about the cost of that power in their rates. This is a very tough balancing act, and we have to be mindful of the need to address these tradeoffs and find the right balance.

I think I want to address a couple of the questions that were posed during the presentation. The question about payment of services versus incentives. If payment for services means that one is paying for power delivered at a competitive market base price, then, yes, then payment for services is far superior to subsidies.

I think everybody, you know, wants a free ride or a free lunch, and I think oftentimes the advocates of distributed generation are working for a public subsidy, and I think we want to be very careful about providing for greater subsidies because somebody has to pay those.

What they end up doing is contributing to higher rates. Again, if payment for services means buying power at a competitively market price rate, then, yes, that is preferable to subsidies.

The issue of loss of revenues. I am not sure if I understand this issue very clearly because by itself, loss of a revenue is not a problem. It is a problem -- if you can lower your costs and your revenue are also lower, there is really no problem here. The problem is if you have lower revenues, but you have high fixed costs or constant fixed costs. That may be a problem.

The problem, again, somebody is subsidizing somebody else. Somebody is getting a free ride here, and we really have to understand who is receiving the benefit, but also who is paying the cost. If this is a problem, there are ways to deal with the problem. There are ways to protect the utility and make it revenue neutral.

We have lots of examples. We use revenue neutrality in energy efficiency programs. We have mechanisms like balancing accounts or (indiscernible) mechanisms that can adjust the revenues accordingly so that there is no harm to the utility. Again, there is no stranded cost.

Just a word about CHP. I sort of shutter using CHP because it has a different connotation in my mind. PG & E purchases about --

PRESIDING MEMBER GEESMAN: Does that come from your experience of Route 80?

MR. GULIASI: Yeah, it does. I've been lucky these last couple of years. I have not received a speeding ticket on Route 80. Other places, yes, but not Route 80.

PG & E receives about a quarter of its

energy from qualifying facilities. About two-thirds of that power that we received from qualifying facilities is from co-generation. The problem here is that we don't always receive the best value for the power that we acquire. There is one problem with respect to how well that power matches our operational needs.

There is also a problem associated with how dispatchable that power is. The power isn't as dispatchable, it doesn't have as great a value as some other power that we might acquire.

The real problem or the biggest problem is that the power that we acquire from QF's happens to be above market price. We pay over $400 million a year in above market prices to meet our QF obligations. That is a problem. It is a problem on its face, but it is certainly problem when you are trying to do your best to manage your costs and to insure that customers have the lowest available rates possible.

There are a couple of proceedings at the Public Utilities Commission that is addressing this issue. I think we have spoken about it before, at least it has been raised her before. Before this commission or the combined commissions make any effort to establish new goals or quantify new goals or place them in higher priority in the loading order, DG, I think we want to be very careful. Watch how those proceedings go and think this process through with your proceeding here in the IEPR.

I think that concludes my remarks. Do you have any questions?

PRESIDING MEMBER GEESMAN: I guess your primary question as it relates to what you suggest here, your $400 million of above market costs, is that in your judgement inherit in your PURPA legal obligation, or is that something you believe the way California has administered PURPA has resulted in those costs?

MR. GULIASI: The problem is really an artifact of how California's implemented PURPA. I believe that the proceeding at the Public Utilities Commissions or the two proceedings are meant to address those issues. One has to do with the contracts that expired. The other one has to do with the setting of the short run avoided costs and the long run costs. We are hoping, again, through the solicitation process to acquire power at more competitively priced market rates.

PRESIDING MEMBER GEESMAN: At least going forward in the hypothetical, that problem could be neutralized?

MR. GULIASI: Yes, in the hypothetical.

COMMISSIONER PFANNENSTIEL: I have just one question. I'm not sure I understand the revenue loss discussion. Does ERAM exist, is there still and Electric Revenue Adjustment Mechanism?

MR. GULIASI: No, we have other such mechanisms for procurement, but --

COMMISSIONER PFANNENSTIEL: They are very specific, and so any revenue loss here would not unless it was separately handled be taken care of?

MR. GULIASI: Yeah, I need to check that, but that is my understanding. I think that ERAM expired, and I don't think that there's been anything, any other mechanism put in its place that would address this problem. If I am wrong, maybe someone who speaks after me might correct what I am saying.

COMMISSIONER PFANNENSTIEL: If you are wrong, would you let me know because I think that would be interesting. Thank you.

MR. GULIASI: Yes, right.

PRESIDING MEMBER GEESMAN: Thanks, Les.

MR. GULIASI: Thank you.

PRESIDING MEMBER GEESMAN: Yes, sir?

MR. KAYE: Thank you, Loren Kaye here for Co-Gen Works. Your Commission obviously gets it, so I'm not going to spend much time up here reinforcing a very well stated support for CHP or co-gen technology, but just to say a couple of things. You do get it as opposed to the ISO and often the PUC and usually the Legislature. So, for that reason, I would urge to be even more forthright and direct in your statements of the importance of this technology.

With regard to the loading order, then, to really say what you mean which is that the State of California, the Energy Policy needs to have a strong CHP co-gen component to it without washing it through or mixing it up in this rhetoric of DG. DG is an important technology and one that serves a very important purpose, but the report really does dilute the impact of what you were saying earlier because it makes a distinction between co-gen, DG, and not co-gen DG, and large DG, and small DG, and it just -- you don't really know what you wind up with there. That is point number one.

Point number two, Mr. Oaki referred to it earlier, but I would like to take the liberty of ramming it home, and that is this one of the few technologies or topic areas that we are talking about today or even in the IEPR report that has the chance of actually going away and where you have existing installed base steel in the ground that is going to be going away.

It is not dirty old plants that are going away that we would like to see go away, these are clean efficient resources that for a lack of public policy or for some focused effort on the part of some policy makers and other commissioners might happen, so just to ram that point home. Thanks.

PRESIDING MEMBER GEESMAN: Thank you, Loren. Other comments? Steven.

MR. KELLY: Sorry to keep you late, my timing is impeccable. I just came off a REGIS call, two hours, but I was able to hear my colleague, Les, say something about the QFs and the "over market price" which I am still alive at the end of the day to respond to that.

I missed part of what he was saying, but one of the impediments to the extent that there is a proceeding at the PUC to determine the true avoided costs of the utilities, and the QF's are prepared to take that price as we always have.

Obviously the biggest impediment of that is the fact that the utilities aren't giving up any information that would give any clue as to what the true avoided cost is. So, that is being litigated at the PUC. So, the argument that there are 400 MWs of above-market QF pricing out there, I just can't let it stand on the record in the absence of any critical evaluation in an evidentiary hearing to challenge that which we haven't had yet.

I just want that to be in front of you. I won't waste any more of your time, but I hope the record explains that PG & E's view is one view of many out there about the over market price of QF's. Thank you.

PRESIDING MEMBER GEESMAN: Thank you, Steven. Any other comments? Yes, sir.

MR. WONG: Commissioners, my name is Eric Wong. I am wearing several hats today. First of all, I am with Cummins Power Generation.

We are a member of the California Clean DG Coalition. I am also a member of the DOE supported Grid Wise Architecture Council.

I've been listening very carefully to the presentation that staff made into your questions. To your question, Commissioner Geesman, I believe there is about this seems to be in limbo, we are not really getting there, you've got a policy that is articulated. I would say that there is something lacking in the execution.

Having been in the trenches of selling co-gen from the end of 2001 through March of 2004, which is based on micro-turbine technology, gas engine technology, and gas turbine technology, it is difficult to sell this. Part of this is due to the fact that it is a long sell cycle. With gas prices fluctuating and volatility that you have, $6 (indiscernible) gas equates to 6 cents, which we try to get our costs under 10 cents to be competitive with utility power.

In the intervening time period that I as selling, the rates have come down to the commercial investor sector making economic potential, and we heard numbers that Mark came out with the technical potential. It greatly reduced that number.

Last year at the CMTA Energy Conference, I made the statement that we still feel that there is about 2,000 to 2,200 MWs economic CHP in California. That is based on about $6 gas. Again, you have to adjust those figures.

I am going to respond directly to what I think are some key issues for this Commission as well as the Public Utilities Commission. There is a question here, given the impending billions to be invested in utility distribution systems, should California strive for evolutionary versus incremental improvements. I would say you need to do both. You've got to keep your eye on the long term, and you need to make the increment improvements.

What are those incremental improvements? I think your evolutionary statement about how much CHP, if you were to pick a goal, I would recommend at least 2,000 MWs, and I am thinking you can go with an aggressive figure that staff has recommended.

There are two big issues that confronts me when I go in and sell. This is also the same hurdle that the members of the California Clean DG

Coalition face, and the members are Capstone, Caterpillar, Chevron Energy -- we've got most of the big players that are trying to sell the CHP in California.

The first issue is what is the role of the utility. This is not clearly defined. I believe that they still have the opportunity and right to sell distributed generation and CHP, but this is something I've seen for the last three years they struggle with.

I'll give you an example, and the staff has quoted the example Detroit Edison. Hawaiian Electric Company has taken it upon themselves to be the primary and sole provider of CHP and distributed generation on the islands. They've got some unique circumstances there. There are some pluses and some minuses, but there may be an opportunity to look at what is going on in Hawaii.

The other big issue that confronts this industry is Rule 218. This the over the fence transaction issue. It is a huge issue for us because when I go out to a business park, a university campus, even Indian casinos, or other large business parks, I look at this as creating a micro grid. I'd rather go across the street or

I've got a wheel within the distribution system.

The Energy Commission has done I think at least one study, a huge study that Navigant and Mark Rawson and his group, if Mark has probably left, is he still here -- that they have done, and they have taken this issue really of a huge step forward, and the US (indiscernible) has personally has a solicitation for micro grids, which closed on July 8. The Rule 218 issue as it pertains to California must be addressed. That is a statutory prohibition, over the fence transactions or power that can export it for one customer to another. I think this issue has to be picked up by this Commission. You need to grapple with the issue and make a decision, are you going to seek legislative relief or not?

Again, those are the two big issues. There are some supporting issues, but the role of the utility and Rule 218 as it applies to micro grids, if you don't like your micro grids, I understand some people don't, then you need to come up with something else, but the concept is very simple. You need to get power distributed within a distribution feeder network, and that can be done. The technology exists, the institutional hurdles and the Public Utility Co-hurdles are what is preventing it from happening today.

Thank you very much.

PRESIDING MEMBER GEESMAN: Do you think there is ambiguity as to the ability of the utility to own equipment?

MR. WONG: No, I said that is provided. The question is there executing that is not clear.

PRESIDING MEMBER GEESMAN: Okay. They have the ability, but they have not chosen to pursue it?

MR. WONG: I know Edison is making some strides in that area, but I don't think they've done, and Gary Schoonyan is here. I've dealt with some of his staff, and they have talked about I think it is in the eastern section of your territory about their grid of the future and looking at distributed generation and CHP. I can't speak for San Diego or Pacific Gas. Thank you.

MR. FREEHLING: Thank you, Commissioners. I'm Robert Freehling again from Local Power. San Francisco has part of its ordinance to implement Community Choice. The requirement, have 72 MWs of distributed generation inside the City of San Francisco, and so rules relating to distributed generation would be quite significant to its plans and likely to plans of other Community Choice aggregators. The problems that were brought up by the last speaker are ones that we would second strongly, the ability to have local distribution networks share power that would allow for a larger facilities.

Some of the problems that are with current combined heat and power, for example, relating to guaranteeing a market and ownership can be overcome to a significant extent by CCAs because the CCAs themselves can plan and own distributed generation facilities.

I don't know if distributed generation in terms of the resolution of this discussion whether you have racketed off renewables entirely from this, is that the case?

PRESIDING MEMBER GEESMAN: I agree with the gentleman that suggested we had too many things bundled into one term. So, the unbundling of the terminology is helpful for me mentally.

MR. FREEHLING: When you say unbundling, you mean distributed generation, we should not be talking about renewables at this point?

PRESIDING MEMBER GEESMAN: I would prefer to speak of renewable DG versus fossil-fired DG.

MR. FREEHLING: All right, very good. Within San Francisco's context that those 72 MWs can be either fossil fuel fired or renewable, but the preference is to have renewable. A number of new technologies are coming on line just at the innovation stage now. I don't know if you are familiar with Verdant Power on the East Coast has developed or is developing a 35 KW title current power generator which has the possibility of generating power today they claim at under 10 cents a KWh.

Such a unit in the San Francisco Bay Area could be hooked up to a customer's site or a local distribution network and used if the technology were proven and if tides in the Bay were measured. So, one of the issues for distributed generation that is renewable is to have much better maps of resources that are available for renewable distributed resources. Current maps of the state for wind, for example, don't provide the level of resolution and detail necessary for implementing local wind power, for example. You would need more than just simply for example a wind map that says this is Class 4, this is Class 3. You would need to be able to say in what seasons and what times of the day, a full map of wind, solar, and other distributed resources.

The Energy Foundation produced recently a Renewable Resource Atlas of the West and even though California has more wind energy than any other state as far as implemented wind energy, our actual measurement resolution of maps for wind energy are not sufficient to know, for example, whether one area of San Francisco would be superior for implementing this versus another.

As far as maps of the currents and tides in the Bay, the implementation putting $100,000 for example into one of these Verdant generators -- I am not selling anything, but the possibility of testing that or another technology in the Bay to see what kind of resources are there or elsewhere in California along the coast or where there are waterways would be very helpful for implementing these.

There are a number of layers of concern depending on whether you are talking renewable generation or distributed generation, but there were a couple of other issues I wanted to go through.

One of them was the integration of renewable distributed or fossil fuel distributed generation is this aspect of integrating distributed generation into the grid. At the moment, a lot of distributed generation, especially the distributed renewable generation, is done on an adhoc basis that you put one here, one there according to whether a customer applies for a rebate or not and wants to here or there.

Community Choice offers the option of actually integrative planning of where you are going to deploy renewables and also the ability to integrate it with other components like energy efficiency and conservation so that you can have a shaped energy product rather than just whenever the wind happens to blow locally, whenever the sun happens to shine locally, or whenever a factory happens to be running with the power.

One of the questions that was raised was integrating energy efficiency and so forth. That level of walking through walls that currently exist in policy would be essential to moving forward for Community Choice cities and I think for distributed generation generally of both types.

Those are the most important things I have to say.

PRESIDING MEMBER GEESMAN: Thank you very much. Other comments from the audience? Gary?

MR. SCHOONYAN: Gary Schoonyan, Southern California Edison Company. Just a couple of comments here. One, and just to piggyback off of the discussion, this one size fits all. I mean it is pretty difficult from our perspective to equate a two KW solar photovoltaic with a 300 MW enhanced oil recovery project. I'll lump them in to DG CHP. There needs to be some segregation there in looking at this.

In doing that segregation, I think from our perspective, one of the tests on the cost effectiveness associated with the application of this, would be a non-participants test very simply.

One of the concerns and you talk about revenue lost, and I think it was brought up that it probably really wouldn't be a revenue loss, it is a revenue shift or a cost shift in most instances to the extent that those costs are not recoverable, like T & D costs or potentially DWR costs or who knows what sort of costs, those tend to be shifted to non-participant.

So, when we are looking at the economics associated with these facilities, it needs to be from a non-participant test. The large contracts, there was some discussion with regards to the existing QF contracts, the rather large ones, the renegotiations. The concern that we have there is there are a lot of benefits associated with CHP. We aren't arguing that. The problem is that the participant wants to keep all of those benefits on his side of the equation and wants other non-participants to pay the full cost associated with the power as if it was a brand new combined cycle facility or something like that. That is the concerns that we have in dealing here.

As far as opening up the books, all of these contracts are available. It is fairly easy to calculate the $400 million PG & E talked about, and I am sure Mr. Kelly has done that. What isn't available is any of the information on the benefits on the customer's side.

What are the benefits they are receiving associated with being able to use the waste heat, we never see those in any sort of negotiation or what have you. I guess from our perspective, is our consumers have paid quite a bit for the development of this, whether it is the $400 million -- and we proposed or actually calculated and submitted to the Commission in the late 90's an uncontested number that over the period that we have had these interim standard offers, it costs our consumers over $20 billion. That number was never contested.

I mean there is a huge price tag that our customers have paid in support of this. I guess all we are saying is, okay, going forward, we can forget about that. Let's share in some of the benefits associated with the CHP type projects. I guess the final comment I had, had to do with DG, and I am not sure whether you were aware of a University of California Energy Institute report that was done in May of 2005, but it was quantifying the air pollution exposure consequences of DG.

There is just one in the abstract associated with it, says, "This investigation has revealed that the fraction of pollutant mass emitted that is inhaled by the down wind exposed population can be more than an order of magnitude greater for all five DG technologies considered than the large central station power plants in California."

I am not saying here again that this is bad, it can't be mitigated and what have you, but I think if we are going to honestly look at DG in a climate change issue or even CHP, that we have to look at it in a fair context associated with other alternatives going forward. DG and CHP isn't a threat to Edison, particularly if it is done as I said from a non-participant perspective, more power to it.

I mean it makes sense. When you can take 60 percent advantage over the energy, that is the way things should be done. Thank you.

PRESIDING MEMBER GEESMAN: Thank you, Gary.

COMMISSIONER BOYD: Gary, I agree with you and all of the other speakers who said we are lumping a whole bunch of subject under one general heading just because it is a simple thing to do, but you are right, it is a real ball of snakes, and it is not that simple, and it needs to be taken apart.

Loren Kaye brought it up first, others have mentioned it, and we need to do it. Those of us, and I know you were there, although during the 2000/2001 years never to forget, particular in 2001 when we were desperately looking for anything and everything in the way of generating electricity, and a lot of us were working on new generation. Some of us were pursuing partial self-gen, self-gen, anything anywhere. Anybody could do anything. Self-gen or just partial self-gen generated KWhs that you didn't have to take off a grid that was not able to provide for us anyway.

Some of us are still suffering four years later from the incredible barriers and frustrations that were placed in front of everybody at that point in time to be able to do anything, even somebody who wanted to put up 49 MW simple cycle process somewhere or a CHP process.

I mean the interconnection process, which has been referenced to, that is in the past, the interconnection fees, the stand by charges, the new ISO charges, the fact that the ISO wants to treat everything that generates electricity as a central plant, and they want to dispatch it.

There are just so many hurdles, it is just a very frustrating thing. I think we are trying to unbundle this ball of snakes and put it in all its various categories. Certainly nobody wants to exacerbate any air quality problem, people do want to improve any climate issues that might come up and just see what we can do in a positive way.

I'm not picking on utilities or you, you just finally prompted me to say something about the past that we are trying to get past in order to deal with this future. Hopefully, everybody and all of the expressions they've made about wanting to look at this subject, we can do just that. There are efficiencies involved in this.

There is waste motion going on out there, not just heat, but we have heard about the other movement of things that could generate electricity in the industrial sector that, you know, its resource recovery so we are not taking advantage of. If we really are short, and we are really having trouble, we should mine that. During the crisis, as you know, none of you and nobody else to speak of had enough resources to build things.

There were industrial people that had money who would be willing to build things. Some people told them I won't do business with government because I've been burned too many times. Those who stepped forward got burned, and there has been a real chill sent through a lot of folks that I think is why we don't see more people stepped up to the plate in this arena and deal with this. We have to set a climate that makes it work for everybody and have as best a level playing field as you can get. We are not mining this area enough in my opinion. Once again, we are beginning to flirt with stuff that makes people nervous in terms of our ability to meet our future needs.

MR. HUNGERFORD: Unfortunately, one of the remnants of the crisis of 2000/2001 were things like bond charges and DWR contracts. Unfortunately, those remnants are effecting planning decisions now because who pays.

COMMISSIONER BOYD: Right, I could start with a clean sheet of paper that didn't include exit fees, it would be a different world as would yours.

MR. HUNGERFORD: Thank you.

PRESIDING MEMBER GEESMAN: Thank you, Gary. Other comments from the audience?

(No response.)

PRESIDING MEMBER GEESMAN: Okay. I'm not certain that we have anything left that I would characterize as a cross cutting issue for discussion, but I will throw out the opportunity for anyone up here or anyone in the audience, any cross cutting issues that need to be discussed.

(No response.)

PRESIDING MEMBER GEESMAN: Thank you very much for your participation. We hope to see you again at our next workshop. We will be adjourned.

(Whereupon, at 4:20 p.m., the workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 4th day of August, 2005.